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Subject:	Filing Accepted for Case: 08-2018-CV-02937; Environmental Law and Policy Center, et al. vs. North Dakota Public Service Commission, et al.; Envelope Number: 3293195
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Envelope Number: 3293195
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Case Style: Environmental Law and Policy Center, et al. vs. North Dakota Public Service Commission, et al.

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Filing Details	
Court	Burleigh County - South Central District
Case Number	08-2018-CV-02937
Case Style	Environmental Law and Policy Center, et al. vs. North Dakota Public Service Commission, et al.
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Lead Document	CR Exhibit 25 Record Addition 3 County Permit Application part 10 of 10.pdf
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($8.3 million, 66.3 percent). (See Table 7.3.)

8. Comparison with Taxation of a California Refinery

Table 8.1 compares the taxation of hypothetical refineries that processed 160,000 barrels of crude oil per-day in Washington and California in 2013.

We focus on six major taxes. One of these taxes—the corporate income tax—is levied in California but not in Washington. Two of these taxes—the business and occupation tax and the hazardous substance tax—are levied in Washington but not in California. The remaining three taxes—the sales and use tax, the property tax and the oil spill tax—are levied in both states.

The overall 2013 tax burden in Washington, $75.8 million, is almost three times the burden in California, $26.3 million. This is largely due to the fact that the Washington refinery pays considerably more in B&O and hazardous substance taxes than the California refinery pays in corporate income tax.

Corporate income tax. California's primary business tax is a corporate income tax. To avoid the complications inherent in state-level income taxation of multi-state businesses, we assume that the corporation owning the refinery does business only in California. California's corporate income tax rate is 8.84 percent. Based on financial information from Tesoro Corporation's 2013 Form 10-K filed with the U.S. Securities and Exchange Commission, we estimate the taxable income for a 160,000 barrels-per-day refinery to be $161.7 million and the corporate income tax due to be $14.3 million.

B&O tax. The B&O tax is Washington's primary business tax. It is a tax on a business's gross receipts. Our 160,000 barrel per day refinery has refined product sales of $6.78 billion. This results in a B&O tax obligation of $32.8 million at the manufacturing/wholesaling rate of 0.484 percent. This is more than twice the corresponding obligation under the California income tax.

The B&O tax is a tax on gross income, without any deductions for the costs of making the goods or services sold, while the corporate income tax is a tax on net income, after deduction of these costs. The B&O tax tends to be more burdensome than a corporate income tax for low margin businesses such as refining.

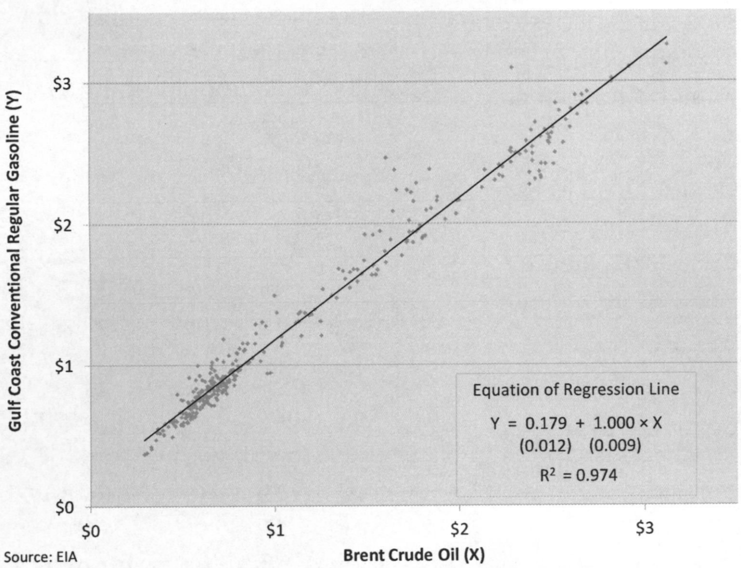
Refinery margins are particularly low when crude oil prices are high. In the

Table 8.1: Taxes on a 160,000 Barrels per Day Refinery, 2013
(millions of dollars)

	Washington	California
Corporate Profits Tax		$ 14.3
Business & Occupation Tax	$ 32.8	
Hazardous Substance Tax	$ 34.8	
Property Tax	$ 5.4	$ 6.6
Sales & Use Tax	$ 1.6	$ 1.6
Oil Spill Tax	$ 1.2	$ 3.8
	$ 75.8	$ 26.3

Source: WRC calcula ons

Figure 8.1: Monthly Average Spot Prices May 1987 – August 2014
Gulf Coast Conventional Regular Gasoline vs. Brent Crude Oil
2009 Dollars Per Gallon



Source: EIA

long run, the prices refiners pay for crude oil passes directly through to the prices they receive for products, as Figure 8.1 illustrates. On the figure we have plotted the monthly average U.S. Gulf Coast spot price of conventional regular gasoline against the monthly average spot price of the benchmark European Brent crude oil from May 1987 to August 2014. The slope of the regression line through the data points is almost exactly equal to one.

Hazardous substance tax. Returning to the taxes listed in Table 8.1, the hazardous substance tax is a second gross receipts tax levied by Washington state. Applying an effective rate of 0.513 percent to gross receipts of $6.78 billion gives a $34.8 million hazardous substance tax obligation for the 160,000 barrel per day Washington refinery. (Based on our survey, we use the 0.513 percent effective rate rather than the statutory 0.7 percent rate to account for various deductions and credits including the credit for product shipped out-of -state in vehicle fuel tanks.)

Property tax. We assume that the Washington refinery is located in the city of Anacortes and that the California refinery is in the city of Martinez. (Shell and Tesoro have refineries in both of these cities.) Based on the taxes paid by the Shell and Tesoro refineries in Anacortes, we estimate that the taxes that would be paid by a 160,000 bbl./day refinery in Anacortes to be $5.4 million. Based on the difference in property tax rates between Anacortes and Martinez, we estimate that such a refinery in Martinez would pay $6.6 million in property taxes.

Sales and use tax. In 2013, the combined state and local sales tax rates was 8.5 percent in both Anacortes and Martinez. Based on the survey of Washington refineries , we estimate transactions subject to the sales and use tax to be $18.8 million and the amount paid to be $1.6 million.

Oil spill tax. Both states impose an oil spill tax. The rate in Washington is 5 cents per barrel. As we noted above, in Washington, 1 cent of the 5 cents is sometimes suspended, and the full 5 cents was only collected in the first three months of 2013. We assume an effective rate of 2.125 percent to account for the credit for product exported from the state. The oil spill tax rate in California is 6.5 cents per barrel, with no credit for exported product. We assume that for both refineries, 58.4 million barrels crude oil are subject to the tax. The oil spill tax burden is $1.2 million in Washington and $3.8 million in California.

9. Petroleum Refining Industry Direct, Indirect and Induced Economic Impacts

The economic impact of refineries on the state's economy can be divided into three primary categories: direct, indirect, and induced effects:

- The **direct** effects are those in the industry itself—the refinery jobs and payroll, and the taxes paid by the refiners.
- The **indirect** economic effects include the jobs, wages, and taxes of upstream suppliers of the refineries—not only the suppliers of crude oil, but also the construction companies and contract workers used for plant maintenance and repair and the office product and equipment suppliers, for example. These figures were captured in the survey completed by the five refiners. The indirect economic effects also include the jobs, wages, and taxes of suppliers' suppliers; of the suppliers' suppliers' suppliers; and so on up the supply chain.
- Finally, the **induced** effects are the jobs, income, and taxes contributed by firms in industries that supply daily consumables and services—e.g., food, dry cleaning, banking—to workers holding the direct and indirect jobs.

The relationship between the direct jobs, income, and tax effects in an industry and their indirect and induced effects are captured by multipliers, which are calculated using the WRC-REMI model of the Washington state economy.

The employment multiplier for the petroleum refining industry is 12.88. Applying this multiplier to the 2,024 direct refinery jobs in 2013 gives a total state employment impact of 24,036 jobs.

This is an unusually large employment multiplier. In comparison, the 2007 Washington state Input-Output Study (2014) calculates that the employment multiplier for manufacturing/construction overall is 2.65. Much of this difference arises because the WRC-REMI model incorporates a number of significant behavioral responses to changes in prices and costs that are not picked up by a simple input-output model: The wage rate depends on the supply and demand for labor, migration and labor force participation rates respond to changes in wage rates, and consumer purchases of specific goods and services respond to changes in relative prices and personal income. In addition, producers substitute among production factors in response to changes in relative factor costs, market shares respond to changes in regional production

Table 9.1: Impact of a 160,000 Barrel Per Day Refinery

565 Direct Jobs

+6,915 Additional Jobs Elsewhere in the State Economy

$92.2 Million Direct Compensation

+$399.5 Million Additional Personal Income Elsewhere in the Economy

$73.7 Million Direct Taxes

+$4.3 Million Additional Sales, Use and B&O Taxes Elsewhere in the Economy

Source: WRC

costs, and investment rises in response to increases in output. When we run the WRC-REMI model with these channels turned off so as to approximate an input-output model, the employment multiplier for petroleum refining is reduced to 4.84. When we run such a WRC-REMI simulation for the larger petroleum and coal products manufacturing sector (the "three-digit" sub-sector of manufacturing that contains the petroleum refining industry) the employment multiplier is 4.05. This is actually less than the 6.80 multiplier that the Washington Input-Output Model gives for petroleum and coal products manufacturing. (This 6.80 is the highest employment multiplier found by the 2007 Input-Output Study.)

Several additional factors contribute to the petroleum refining industry's large multiplier. First, petroleum refiners pay high wages. As a result, the employment induced by refinery employee spending is relatively great. Second, the petroleum industry ranks high in the ratio of in-state supplied intermediate inputs (including contract labor) to employee income. For this reason, indirect employment is relatively high. And some of these indirect jobs (contract labor, in particular) pay unusually high wages.

The WRC-REMI model calculates that each refining job results in an additional $880,142 of state personal income. At 2013 employment levels, the industry adds $1.8 billion to state personal income.

In 2013 state and local sales and use taxes averaged $0.0270 for each dollar of state personal income. With the income multiplier of $880,142, each petroleum refining job results in $26,324 in state and local sales taxes or a total of $53.4 million.

The refiners directly paid $105.1 million in B&O taxes in 2013. In 2009 state B&O taxes averaged $0.00106 for each dollar of personal income. Multiplying this rate into $1,452.9 million—the increase in state personal income we ascribe to the 1,986 refinery jobs net of the wages and benefits of the refinery workers—gives $15.4 million additional induced and indirect B&O tax revenue, for a total of $120.5 million, or $60,691 per direct job.

These impacts can be expressed in terms of the hypothetical Washington refinery producing 160,000 barrels of product a day that was analyzed in Section 8. In 2013, this refinery would have provided 565 jobs, and these workers would have received $68.4 million in wages and salaries and $25.3 million in benefits. In addition to the direct jobs and income, the refinery would generate 6,915 jobs and $399.5 million in personal income elsewhere in the state's economy. The refinery itself would pay $73.7 million in state and local taxes. In addition to these direct taxes, the indirect and induced activities generated by the refinery would provide $4.3 million in sales, use and B&O tax revenue. (See Table 9.1.)

10. Washington Petroleum Industry: Downstream Activities

Washington's petroleum refiners rely on a number of industries to distribute their product to consumers. These include transportation (pipelines, barges, trucks, and rail) and transportation support facilities (terminals, stockyards, and bulk stations), wholesalers, and retailers

Table 10.1: Employment and Wages by Industry, 2013

Industry (NAICS Code)	Firms	Total Wages Paid	Average Employment	Average Annual Wage
Petroleum Bulk Stations and Terminals (424710)	38	$45,169,000	716	$63,092
Other Petroleum Merchant Wholesalers (424720)	94	$63,632,000	1,085	$58,661
Gasoline Stations With Convenience Store (447110)	1,730	$230,081,000	12,109	$19,001
Other Gasoline Stations (447190)	112	$24,395,000	958	$25,455
Fuel Dealers (45431)	120	$49,627,000	1,038	$47,799
Refined petroleum product pipelines (48691)	7	$14,979,000	138	$108,346
Crude Oil Pipelines (48611)	D	D	D	D

Source: BLS

D: Value not disclosed

(gasoline stations and fuel oil dealers).

These downstream industries exist as a result of petroleum product consumption in our economy, not as a result of petroleum refining. Presumably, if the refineries were gone or if they had never existed in Washington, finished petroleum products would be imported to terminal and stockyard facilities, transported to retail destinations within the state, and sold to consumers through systems much like those that currently exist, together with similar job, wage, and tax effects. Even so, their direct economic contribution is substantial and their role in the larger petroleum industry is crucial. This section describes the employment, wages, and taxes associated with these industries.

Of the total finished products produced by Washington's refineries, 48 percent leaves through pipeline to markets in Seattle and Tacoma and beyond. Another 39 percent goes by water to Seattle, Portland, or elsewhere with the remaining 13 percent of product shipped by rail or truck. About 50 percent of product is delivered to retailers for consumer sales within the state of Washington (Appendix A).

Jobs and wages. According to detailed data reported to the BLS for 2013, the most recent year for which such data are available, there were about 2,100 employers in these downstream industries. Together, they paid $428 million in wages to 16,044 workers. These are all workers covered by unemployment insurance in these industries, so the number includes both full-time and part-time workers. Table 10.1 shows these data for each industrial classification with its corresponding North American Industrial Classification System (NAICS) code.

Among the downstream industries there are three broad tiers of employment and pay:

- Refined petroleum product pipelines employ a few highly paid workers—138 workers made $108,346 (plus benefits) on average in 2013.
- Bulk stations and terminals, wholesalers, and fuel oil dealers employ about 2,839 workers who earned on average $55,804 in 2013.
- Gasoline stations generate a large wage bill with a lot of lower-wage and part-time jobs. In 2013, this industry's 1,842 employers paid

total wages of $254.6 million to 13,067 workers.

Taxes. The state Department of Revenue (DOR) reports excise tax data on these same industries (DOR 2014a, 2014b).

As shown in Table 10.2, total excise taxes due from the downstream industries equaled $236.2 million in 2013. Gasoline stations paid $156.7 million in excise taxes. Wholesalers paid $59.9 million; fuel dealers, $19.6 million.

Table 10.2: Taxable Income and Taxes Due by Industry, 2013 (millions of dollars)

Industry (NAICS Code)	Gross	Taxable	B&O Tax	Other Excise	Total
Petroleum Products Wholesaling (4247)	7,667.4	6,079.4	29.9	30.0	59.9
Gasoline Stations (4471)	12,015.1	9,907.2	47.9	108.8	156.7
Fuel Dealers (45431)	540.5	510.3	2.5	17.1	19.6
Refined petroleum product pipelines (48691)	D	D	D	D	D
Crude Oil Pipelines (48611)	D	D	D	D	D

Source: DOR

D: Value not disclosed by DOR

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Appendix A

A.1: Quantity and Value of Feedstock Inputs	2012	2013
Feedstock Quantity (KBBLS/Day)		
Crude Oil	528.4	572.3
Other	14.5	19.0
Total	542.9	591.3
Feedstock Value ($K)		
Crude Oil	20,296,503	22,012,122
Other	376,451	482,324
Total	20,672,954	22,494,447

A.2: Quantity and Value of Output	2012	2013
Output Quantity (KBBLS/Day)		
Gasoline	244.0	257.1
Diesel Oil	123.0	156.8
Jet and Turbine Fuel	77.6	83.7
Calcined Coke	5.0	6.5
LPG	6.2	9.0
Residual Fuel Oil	25.6	23.7
Propane	8.7	9.8
Coke	5.5	4.9
Sulfur	0.9	1.1
Marine Fuels	18.7	13.9
Gas Oils	17.0	13.0
Emulsified and Road Asphalt	3.0	3.0
Other	19.6	23.8
Total	554.8	606.2
Output Value ($K)		
Gasoline	11,131,333	11,283,582
Diesel Oil	5,925,518	7,180,577
Jet and Turbine Fuel	3,607,739	3,776,891
Calcined Coke	240,571	274,427
LPG	147,581	186,164
Residual Fuel Oil	954,440	761,980
Propane	110,292	143,743
Coke	46,945	46,263
Sulfur	10,802	7,245
Marine Fuels	732,733	486,125
Gas Oils	492,609	369,691
Emulsified and Road Asphalt	108,848	88,554
Other	404,719	460,997
Total	23,914,129	25,066,238

A.3: Origin of Inputs 2013	Crude Oil	Other
(KBBLS/Day)		
Alaska	264.4	2.9
Canada (Conventional)	105.4	-
Canada (Oil Sands)	49.6	-
Bakken	79.3	-
All Other Origins	73.7	16.1

A.4: Destination of Output 2013	Washington	Other U.S.	Foreign	Total
(KBBLS/Day)				
Gasoline	118.7	116.6	21.8	257.1
Diesel Oil	77.2	57.8	21.8	156.8
Jet and Turbine Fuel	47.6	15.4	20.8	83.7
Calcined Coke	-	-	6.5	6.5
LPG	8.6	0.3	-	9.0
Residual Fuel Oil	12.9	3.2	7.6	23.7
Propane	8.3	1.5	-	9.8
Coke	3.0	2.0	-	4.9
Sulfur	1.0	0.0	-	1.1
Marine Fuels	12.1	1.8	-	13.9
Gas Oils	2.0	11.0	-	13.0
Emulsified and Road Asphalt	2.0	1.0	-	3.0
Other	3.8	20.0	-	23.8

A.5: Mode of Transport 2013	Pipeline	Water	Truck	Rail
Feedstocks (KBBLS/Day)				
Crude Oil	155.7	346.1	0.1	70.4
Other	1.8	8.0	0.2	9.1
Outputs (KBBLS/Day)				
Gasoline	159.2	77.6	20.3	-
Diesel Oil	77.4	63.7	15.6	0.1
Jet and Turbine Fuel	37.6	33.0	13.2	-
Calcined Coke	-	-	0.2	6.3
LPG	5.7	-	-	3.3
Residual Fuel Oil	-	23.7	-	-
Propane	0.1	-	7.2	2.4
Coke	-	2.0	-	3.0
Sulfur	-	-	1.1	-
Marine Fuels	-	13.9	-	-
Gas Oils	-	13.0	-	-
Emulsified and Road Asphalt	-	-	2.0	1.0
Other	-	16.7	-	7.1

A.6: Employment and Contract Labor	2012	2013
On-Site Employment		
Number of FTE Employees	1,996	2,024
Total Payroll ($K)	248,408	245,134
Total Employee Benefits ($K)	91,579	90,586
Contract Labor		
Expenditure ($K)		
Service and Maintenance	517,015	321,197
Capital Repair and Replacement	80,889	91,709
Total	597,903	412,906
Number of Contract Workers (FTE)		
Service and Maintenance	1,790	1,599
Capital Repair and Replacement	1,053	1,128
Total	2,843	2,727
% of Contract Labor from Outside WA State		
Service and Maintenance	19%	10%
Capital Repair and Replacement	25%	50%

A.7: Operating Expenditures Other than Labor or Feedstock ($K)	2012	2013
Non-Durable Manufactured Goods		
Petroleum Products	240,056	234,633
Other Non-Durable Goods	42,544	40,235
Total	282,600	274,868
Durable Manufacturing	-	-
Construction	178,368	75,900
Transportation		
Rail	27,188	61,653
Trucking	8,557	4,956
Automobiles	9,479	5,360
Waterborne	216,837	223,115
Air	-	-
Other	17,123	19,419
Total Transportation	279,185	314,503
Utilities and Communications		
Electricity	48,745	64,952
Gas	140,716	211,872
Other	14,450	17,824
Total U&C	203,911	294,647
Finance, Insurance and Real Estate	8,029	45,858
Business Services	6,213	6,109
Other Services	37,067	40,076

A.8:. Non-Labor Capital Expenditures	2012	2013
Equipment ($K)	95,261	139,241
Materials and Supplies ($K)	53,451	121,808
Total	148,712	261,050

A.9: Taxes and Fees		
Taxes ($K)		
Retail Sales and Use tax	3,182	5,919
Business and Occupation Tax	101,517	110,028
Property Tax	23,371	24,270
Unemployment Compensation Tax	934	1,067
Hazardous Substance Tax	109,339	116,746
Oil Spill Tax	7,943	8,343
Petroleum Products Tax	-	-
Motor Vehicle Fuel Tax	530	514
Special Fuel Tax	52	33
Other	1,586	1,662
Regulatory Fees ($K)		
Air Operating Registration and Permit Fees	1,957	2,061
Waste Disposal Fees	2,126	1,330
Wastewater Discharge Fees	794	821
Building Inspection Fees	3,879	8,345
Building Permit Fees	30	35
Other	40	109
Industrial Insurance Premium ($K)	9,210	6,966

A.10: Estimated Services and Retail Trade		
Food Services ($K)		
Associated with Contract Labor	372	415
Associated with Business Visitors	505	579
Total	877	994
Hotel and Motels ($K)		
Associated with Contract Labor	634	653
Associated with Business Visitors	695	665
Total	1,329	1,318
Other Trade and Services ($K)		
Associated with Contract Labor	25	25
Associated with Business Visitors	61	70
Total	86	95

A.11: Contributions ($K)		
Corporate	755	807
Firm-Sponsored Employee Giving	860	908

A.12:. Other ($K)		
Estimated Business visitors from outside Washington	3,050	2,450

Appendix B

Petroleum Product Exports from Washington State

	2013		2012	
Canada	$2,177,833,636	1	$1,781,345,720	1
Mexico	$829,871,226	2	$1,082,484,856	2
Chile	$799,600,716	3	$321,653,747	3
Singapore	$246,697,826	4	$244,062,973	4
Peru	$151,040,493	5	$439,895	19
Panama	$101,230,413	6	$497,533	18
Australia	$96,604,700	7	$138,680,487	5
Guatemala	$95,946,791	8	$38,177,596	9
China	$71,483,403	9	$67,575,139	6
Brazil	$64,440,635	10	$64,750,640	7
New Zealand	$40,964,163	11	$52,736,383	8
Thailand	$17,846,188	12	$233,353	21
United Arab Emirates	$14,671,853	13	$7,409,777	13
Ecuador	$9,773,181	14	$34,457,684	10
Colombia	$9,348,212	15	$213,812	22
Indonesia	$8,461,078	16	$8,180,664	12
India	$8,244,201	17	$2,023,767	16
Belgium	$8,000,000	18	$16,142	32
Japan	$7,325,684	19	$5,377,778	14
Taiwan	$3,650,060	20	$3,471,180	15
Russia	$3,484,204	21	$621,938	17
Malaysia	$549,305	22	$10,705,014	11
Philippines	$394,911	23	$364,487	20
Dominican Republic	$167,947	24	$172,401	23
Costa Rica	$137,888	25	$125,102	24
Germany	$110,370	26	$49,032	27
Nicaragua	$96,226	27	$19,487	31
Kazakhstan	$94,789	28	$14,120	34
Vietnam	$40,451	29	$116,818	25
Guadeloupe	$31,109	30	$0	-
Saudi Arabia	$25,242	31	$0	-
Uruguay	$21,101	32	$0	-
Trinidad And Tobago	$17,531	33	$11,195	37
French Polynesia	$16,802	34	$8,401	39
Fiji	$9,444	35	$0	-
Barbados	$8,483	36	$4,448	42
United Kingdom	$5,535	37	$26,097	28
Czech Republic	$5,440	38	$7,400	40
New Caledonia	$5,260	39	$0	-
Korea, Republic Of	$4,607	40	$26,033	29
Switzerland	$3,996	41	$0	-
Hong Kong	$3,561	42	$88,040	26
Netherlands	$3,480	43	$0	-
Norway	$2,886	44	$0	-
Spain	$2,613	45	$5,280	41
Haiti	$2,580	46	$13,960	35
Jamaica	$0	-	$23,234	30
Maldive Islands	$0	-	$15,196	33
Denmark	$0	-	$12,000	36
Austria	$0	-	$8,799	38
France	$0	-	$2,559	43
Total All Countries	$4,768,280,220		$3,866,230,167	

Source: WISERTrade

Appendix C

The Washington Research Council uses a model of the Washington state economy constructed especially for WRC by Regional Economic Models, Inc. Because it allows supply and demand to respond to changes in prices and wages, and permits substitution among factors of production, the WRC-REMI model is more elaborate than the standard input-output models commonly employed to estimate regional economic impacts (Treyz 1993).

The standard input-output model fails to model the numerous capacity constraints within the economy, the processes that set prices for goods and services and the responses of consumers and producers to changes in these prices. In the input-output model, industry and labor supply are perfectly elastic—so prices and wage rates do not matter.

Prices and wages do matter in the WRC-REMI model. The model divides the state into two sub-regions: The Seattle Metropolitan District (King and Snohomish Counties) and the balance of the state. There are 66 private industrial sectors within each sub-region, as well as four governmental sectors. Within each sub-region the model tracks inter-industry transactions, much as an input-output model would.

Unlike an input-output model, however, the WRC-REMI model incorporates a number of significant behavioral responses to changes in prices and costs: The wage rate depends on the supply and demand for labor, migration and labor force participation rates respond to changes in wage rates, and consumer purchases of specific goods and services respond to changes in relative prices and personal income. In addition, producers substitute among production factors in response to changes in relative factor costs, market shares respond to changes in regional production costs, and investment rises in response to increases in output.

This report uses version PI+ 1.5.2 of the WRC-REMI model.

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SEH

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MEMORANDUM

TO: Kimberly Fischer, Hydrologist
North Dakota State Water Commission

FROM: Scott A. Lange, PE
Project Manager

DATE: January 26, 2017

RE: Meridian Energy Group Water Appropriation Public Informational Meeting Questions
SEH No. MERID 135471 14.00

SEH received your December 22, 2016 email which condensed the comments and concerns provided to the State Water Commission during the public comment period for the Meridian Energy Group (Meridian) Water Appropriation Permit Application No. 6858. SEH has taken your questions and numbered them for quicker reference. Below are responses provided by Meridian to all questions, while noting that some of the items are not explicitly related to the Water Appropriations Permit Application and will not become a topic during the February 8, 2017 Information Meeting to be held in Medora, North Dakota.

1) **How will the water be used in the refinery?**
Water drawn from the Dakota Formation will be treated to provide water with the quality required for make up to the cooling system, boiler feed water system, process water, and utility water needs of the refinery. Additionally, the use of surface water run-off as a possible source of raw water is being considered to reduce the overall cost of raw water treatment.
    - Cooling System. The refinery design is maximizing the use of air cooling in order to keep to a minimum the water requirements for cooling purposes. In addition, as long as water quality is suitable, water used by the cooling system will be recycled to minimize make up water requirements.
    - Steam Generation: Onsite processes will use heat integration as much as possible to minimize steam for heating needs. As with the cooling system, the intent is to recover any condensation in the system to be reused for steam generation and minimize make up water needs to the steam generation system.
    - Process Water: The main process water user is the desalter within the atmospheric distillation unit. The refinery design includes recycling of treated wastewater back to the refinery processes to minimize the raw water make up needs.

2) **Provide an overview of how water will be used starting with the formation and details on how the water will be treated.**
Water will be drawn from the formation, treated with a Reverse Osmosis (RO) unit to provide plant process/cooling/steam water.

3) **Will the refinery use a wet or dry scrubber and how will it affect the water quantity needed?**
The current refinery design does not include the use of either a wet or dry scrubber to control air emissions.

4) **Will a plume be created by the refinery?**
A visible plume may be created from the cooling water towers. Since the refinery will maximize the use of air cooling, and the cooling towers will be designed with drift eliminators, Meridian anticipates any visible plume from the cooling water towers to be minimal.

5) **What waste products will be created and how will they be handled?**
The waste product from the treatment of brine water drawn from the Dakota Formation will be the reject from the RO process. It is currently estimated that RO reject will account for about 40% of the refinery water demand. Management of the RO reject is currently under evaluation with several possible methods being considered, which include:
- Onsite injection back into the Dakota Formation via a permitted underground injection well.
- Offsite injection.
- Onsite evaporation.

6) **Will an onsite injection well be drilled or will waste travel by pipeline or truck to an offsite injection well?**
See item number 5.

7) **Onsite waste storage?**
At this time, Meridian does not anticipate that onsite waste storage will be required to handle RO reject. This will be finalized once test wells are drilled and management of RO reject is fully defined. The exact details of handling the treatment water brine are yet to be determined. If the disposal process is with onsite wells, evaporation, or offsite piping; there will be little to no storage as the disposal will happen in real time. If trucking is involved with the disposal process, some tanked storage will be needed.

8) **Is the water volume requested for both Phase 1 and 2?**
Yes.

9) **What is the timing for the phases?**
It is anticipated it will take one to five years to transition from Phase 1 to Phase 2.

10) **Concern about how much water is actually needed.**
Water need was calculated based on the make-up water demand and making some assumptions on the level of loss during raw water treatment and the amount of treated wastewater than can be recycled. The make-up water demand will be in the order of 150 to 300 gallons per minute. The treated water recovery rate through the RO system is anticipated in the 40- to 60% rate, and will be confirmed once test well(s) are drilled. Based on these assumptions, we settled on a request of 400 gpm from the formation.

11) **The originally stated projections of water requirements appear to be four times less that the volume included in the application.**
See item number 10.

12) **The volume of water requested is significantly less that the water volume used by the Tesoro Refinery in Mandan.**
The Davis Refinery design includes plans to recycle treated wastewater, to the extent feasible, as raw water for plant processes in order to minimize the draw of water from the Dakota Formation as well as the need for wastewater disposal. Additionally, the Tesoro Refinery is located near ample water sources and can use other cooling methods in their process.

13) **Concern about the water quality in the Dakota aquifer, and impact of any release to the air.**
Based on available groundwater data and because the intended treatment for the water drawn from the Dakota Formation is through a closed system which will not vent to the atmosphere, no impacts to air are anticipated.

14) **Is the water quality from the Dakota aquifer safe for industrial use?**
This is a suggested source of water for industrial purposes by the North Dakota Energy and Environmental Research Center at UND.

MRL/djg

c: William C. Prentice, Meridian Energy Group, Inc.
Tom Williams, Meridian Energy Group, Inc.
Dan Hedrington, SEH

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NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
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September 16, 2016

Mr. Tom Williams
Meridian Energy Group, Inc.
2070 Business Center Drive, St 160
Irvine, CA 92612

Re: Draft Modeling Protocol

Dear Mr. Williams:

The North Dakota Department of Health (Department) received a draft modeling protocol for the Meridian Energy Group, Inc. (Meridian) Davis Refinery in August 2016. While most of the information provided in the draft modeling protocol is in line with the *NDDoH Air Quality Dispersion Modeling Analysis Guide* and the *Site Specific Modeling Guidance*, a few points have been clarified below. The *Site Specific Modeling Guidance* was intended to be a broad outline of modeling requirements required by the Department; however, the facility must make some modeling determinations due to the specific equipment to be at the facility. All modeling must comply with EPA guidance documents and Department policy. Any questions related to a specific modeling parameter or guidance should be directed to the Department.

It is noted that the draft modeling protocol includes draft emissions estimates. While the Department recognizes that the emissions estimates are preliminary, the Department has significant concerns regarding the estimated emissions which are outlined in Section 3.3 below. We advise Meridian to ensure that any emission rates relied on when completing the permit application are based on guaranteed emission rates which have been demonstrated in practice on a similar source on a long-term basis.

Section 1.0 Projected Background

Short range impacts are 20 km (not 10 km) as outlined in *NDDoH Air Quality Dispersion Modeling Analysis Guide*.

Section 2.0 Project Description

This modeling protocol will apply if the facilities' emissions are less than PSD major source thresholds for Petroleum Refineries. Should emissions exceed the PSD major source threshold, a new protocol will need to be submitted and approved prior to conducting the modeling analysis.

Section 3.2 Plant Stack Data

Flare stacks are not included in Table 2—Preliminary Plant Stack Parameters. The Department utilizes a November 10, 2010 Guidance Document *Model Input Parameters for Flares* for how to model emissions from flares.

Section 3.3 Plant Emissions Data

Meridian has stated the project will be a synthetic minor source, to be verified by the Department upon receipt of a completed Permit to Construct application. The Department will review emission calculations and equipment specifications when submitted; however, the emission values submitted in the draft modeling protocol are very low and may not be achievable. Given this uncertainty, total emissions must be carefully considered and PSD applicability must be determined prior to application submittal. If the emissions exceed PSD major source thresholds, then Meridian should consult with the Department and the Federal Land Managers (FLMs) regarding PSD modeling requirements. The Department has provided information under the assumption that this facility will not be a major PSD source. Should the Davis Refinery be a major PSD source, the Site Specific Modeling Guidance document issued to Meridian will become invalid.

Preliminary potential emissions estimates from the facility are shown in Table 4 of the draft protocol. The Department recognizes that the emissions shown are preliminary estimates and more detailed emissions estimates (along with the emissions calculations) will be provided with the application for a Permit to Construct. However, based on the preliminary information in Table 4, the Department has the following comments:

1. When preparing emissions calculations and proposing limits for the facility's emissions units, the Department requires that the technology proposed has been demonstrated effective at an existing facility. To streamline the review, Merdian should provide the respective documentation indicating the technology has been demonstrated in practice.

2. Regarding the preliminary potential VOC emissions, the Department has the following comments:

   a. The State of California has some of the strictest VOC emissions regulations in the United States and several refineries operate in the state. A list of refineries operating in the state can be found at: http://energyalmanac.ca.gov/petroleum/refineries.html. The Department reviewed the 2014 VOC emissions data for four refineries and the information is summarized below:

Refinery	Capacity (bpd)	2014 VOC Emissions (tons)	Emission Factor (lb VOC / bbl)*
Kern Oil and Refining	26,000	71.6	0.015
San Joaquin Refining	15,000	65.1	0.024
Greka Energy, Santa Maria	9,500	41.5	0.024
Phillips 66, San Francisco	78,000	403	0.028

* The emission factor is calculated assuming that the facility operated 365 days per year at maximum capacity, which is a highly conservative assumption. Using actual crude oil throughput for the facility would result in a higher emission factor.

Table 4 of the draft protocol estimates potential VOC emissions of approximately 81 tons/year, which equates to approximately 0.0081 lb VOC / bbl (assuming the facility operates 365 days/year at 55,000 barrels per day). The preliminary VOC emissions estimates for the Meridian facility are approximately two to three times lower (on a lb VOC / bbl basis) than those from refineries operating in California (which, as indicated previously, has very strict regulations regarding VOC emissions). Assuming that VOC emissions from the Meridian facility will be controlled as well as the above-referenced refineries, VOC emissions from the Meridian facility would be expected to be approximately 150-280 tons/year. This level of VOC emissions is above the PSD major source threshold of 100 tons/year.

b. VOC emissions from the FCCU, catalytic reforming unit and the vacuum systems are listed as 0.00 tons/year. It is unclear why no VOC emissions are estimated from these units.

c. VOC emissions from storage tanks are listed as approximately 4.4 tons/year. This number appears to be very low for a facility with a 55,000 barrel per day crude oil throughput, especially considering that crude oil from the Bakken formation has a relatively high Reid Vapor Pressure (RVP). The Department generally accepts a RVP of 10-12 for use in calculating emissions of facilities storing or transmitting Bakken crude oil.

Additionally, the Department will require details on the proposed vapor recovery system for the tanks. Currently, the Department is unaware of any facilities where a vapor recovery system is installed on the entirety of the tank farm at a petroleum refinery.

d. VOC emissions from leaks are listed as approximately 34.1 tons/year. This number appears to be very low for a full-scale refinery with a capacity of 55,000 barrels per day.

3. Regarding the preliminary potential NO_x emissions, the Department has the following comments:

a. NOx emissions from the stationary combustion sources are listed as approximately 35.2 tons/year. This NO_x emissions estimate for combustion sources appears to be very low for a full-scale petroleum refinery with a capacity of 55,000 barrels per day.

Based on the VOC emissions from the stationary combustion sources and using the AP-42 VOC emission factor for natural gas combustion, the Department back calculated the estimated fuel usage at the facility. Using this number, paired with the NSPS Ja standard for NO_x, the facility would be over 100 tons/year just from the combustion sources. Assuming SCR injection on the largest units (or the few largest boilers/process heaters) will still amount to emissions near 100 tons/year from combustion sources alone.

b. NO_x emissions from the flares are listed as approximately 0.46 tons/year. This NO_x emissions estimate for flaring appears to be very low for a full-scale petroleum refinery with a capacity of 55,000 barrels per day.

c. NO_x emissions from the FCCU are listed at 3.37 tpy. As indicated in the protocol, the NO_x control efficiency is assumed to be 98%. This is not consistent with the Department's understanding of typical FCCU NO_x emissions.

4. Regarding the preliminary potential CO emissions, the Department has the following comments:

a. CO emissions from the stationary combustion sources are listed as approximately 0.03 tons/year. This CO emissions estimate for combustion sources appears to be very low for a full-scale petroleum refinery with a capacity of 55,000 barrels per day. For example, 99.99% control on CO with "burner adjustments" with no additional CO control is not known to be achievable.

b. CO emissions from the flares are listed as approximately 2.1 tons/year. This CO emissions estimate for flaring appears to be very low for a full-scale petroleum refinery with a capacity of 55,000 barrels per day.

c. CO emissions from the FCCU are listed at 0.00 tpy. As indicated in the protocol, it is assumed that the CO control efficiency is 100%. This is not consistent with the Department's understanding of this units operation. For example, operating under the assumption the CO boiler will destroy all CO from the FCC regenerator is not a reasonable assumption as CO is still produced as a result of supplemental fuel gas combustion within the boiler. A realistic CO emission rate will need to be established for this source.

5. Regarding the preliminary potential HAP emissions, the Department has the following comments:

a. HAP emissions from leaks are listed at 0.00 tons/year. The Department is not aware of any technology that will result in zero HAP emissions from equipment leaks at a petroleum refinery.

b. HAP emissions from stationary combustion sources are listed at approximately 0.02 tons/year. This HAP emissions estimate for combustion sources appears to be very low for a full-scale petroleum refinery with a capacity of 55,000 barrels per day.

c. HAP emissions from the FCCU, catalytic reforming unit and the vacuum systems are listed as 0.33, 0.00 and 0.00 tons/year, respectively. It is unclear why no HAP emissions are estimated from the catalytic reforming unit and the vacuum systems; in addition, the HAP emissions from the FCCU appear to be very low.

d. HAP emissions from product loading are listed as 0.0 tons/year. The Department is not aware of any technology that will result in zero HAP emissions from product loading at a petroleum refinery.

6. Filterable PM_{10} emissions from stationary combustion sources are estimated at 0.00 tons/year; however, filterable $PM_{2.5}$ emissions from the stationary combustion sources are shown at 15.98 tons/year. PM_{10} emissions include $PM_{2.5}$ emissions and as such PM_{10} emissions should be equal to or greater than $PM_{2.5}$ emissions.

In general, based on the Table 4 PM emissions (PM_{10}, $PM_{2.5}$, and PM_{cond}), there appear to be several errors with the emissions calculations for PM.

As indicated above, many of the emissions estimates included in the draft protocol appear to be very low for a full-scale petroleum refinery with a capacity of 55,000 barrels per day. Emissions calculations and documentation of the basis for all emissions estimates must be submitted with a permit application for the Meridian facility. Documentation of an emission rate must clearly demonstrate that the emission rate has been achieved in practice on a long-term basis at a similar source before the Department will accept that the emission rate is an accurate representation of expected emissions from the facility.

Section 4.1 General Requirements

Table 5—Summary of NAAQS Significant Impact Levels for Preliminary Screening Analysis. The Department has our own PM_{10} Class I SIL of 0.2 $\mu g/m^3$ (24-hour) and 0.1 $\mu g/m^3$ (annual) as listed in *NDDoH Air Quality Dispersion Modeling Analysis Guide*. This SIL should be used along with the federal SILs.

Meridian should also model all SILs in accordance with EPA guidance for modeling SILs as clarified since the $PM_{2.5}$ SIL was challenged.

The protocol discusses the use of AERMOD in SCREEN mode. While our *Air Quality Dispersion Modeling Analysis Guide* does allow for possible exemption from further refined modeling if SCREEN modeling shows maximum concentration below the SILs, the Department urges caution in using this due to the facility's proximity to a Class I area and the limited ability of AERSREEN in modeling complex facilities such as a refinery. If AERSCREEN modeling results show values under the SILs, the Department may still require refined modeling of NAAQS, NDAAQS, and/or other modeling to be conducted.

Section 4.2 PSD Increments

For PSD increments plant fence line shall be used as the ambient air boundary, as it limits public access to the facility. In the event there is no fence or other means of restricting access, the buildings are considered the ambient air boundary. The means of restricting public access should be specified.

Table 6—Prevention of Significant Deterioration (PSD) Class II Increments omits the $PM_{2.5}$ increment of 9 $\mu g/m^3$ (annual) and 4 $\mu g/m^3$ (24-hour).

Section 4.3 NAAQS Standards

For NAAQS/NDAAQS increments plant fence line shall be used as the ambient air boundary, as it limits public access to the facility. In the event there is no fence or other means of restricting access, the buildings are considered the ambient air boundary. The means of restricting public access should be specified.

Table 7—National and Oregon Ambient Air Quality Standards (NAAQS & OAAQS). Use North Dakota Ambient Air Quality Standards (NDAAQS), including the H_2S ambient standard. NDAAQS can be found in NDAC 33-15-02.

NAAQS and NDAAQS must be met at all locations within the model domain, not just at the plant boundary or fence line. New sources can not violate AAQS on their own or *contribute* to a violation of an AAQS when emissions combine with other sources.

The table also omits the new 1-hour NO_2 and SO_2 NAAQs and NDAAQS. Also note that on October 26, 2015 the EPA revised its NAAQS ozone standards.

Section 5.1 Model Options

The use of a 75% (0.75) in-stack NO_x to NO_2 ratio for annual averages is acceptable; however 80% (0.8) is the allowable NO_x to NO_2 ratio allowed for one-hour averages without further justification. If Meridian wishes to use a value other than 80% for one-hour averages the alternate value will need to be adequately justified based on vendor specification and consultation with the Department before use.

The use of MAKEMET is allowable for AERSCREEN. Please note that the Department prefers the use of 1-minute data and AERMINUTE for AERMOD use; which may be required if refined modeling is required.

Modeling tanks, loading stations, and leaks (fugitives) as area sources is acceptable. If an emission point would be better modeled as a point or line source the Department is not limiting tanks, loading station, and leaks to only area source modeling, but explain the choice of point, area, or line for each emission point.

Flare sources should be modeled according to NDDoH's *Model Input Parameters for Flares* policy.

The use of flat terrain for AERSCREEN is allowable for preliminary model testing; however, it will not be accepted for purposes of the final modeling analysis. DEM or NED data processed in AERMAP should be conducted.

Section 5.2 Ambient Conditions

Meridian should use the standard background as listed in *NDDoH Air Quality Dispersion Modeling Analysis Guide* for any SCREEN modeling and use the Painted Canyon and Dunn Center monitoring site data for refined modeling.

Section 5.4 Receptors

Nested Cartesian receptor grids are specified in the *NDDoH Air Dispersion Modeling Guide*. Receptors should be 25 m along the fence line, 100 m spacing for 1- 5 km, and 250 m spacing for 5-10 km, and 500 m spacing for 10-20+ km from fence line. Any part of the property that is not within a fence limiting access must be included in the receptor grid. Any portion of the property with a fence line and not accessible by the public is not considered ambient air and may be excluded from the receptor grid.

Maximum grid extent depends on the buoyancy (plume height) of the source. Meridian should include a discussion on grid extent and domain in their modeling analysis, though the Department requires a 20 km domain at minimum.

More compacted grid spacing should be utilized in areas where a maximum modeled impact occurs in a coarse portion of the primary receptor grid.

Section 5.5 Increment Consuming and Interactive Sources

Along with Dakota Prairie Refinery to be included as a nearby source in all modeling, if refined modeling using non-standard background (i.e. monitoring site data as background) then Whiting Oil and Gas Corp.'s Belfield Gas Plant will be included as a nearby source. Meridian may contact the Department for emission rates from this source if refined modeling is needed.

Section 5.7 Good Engineering Practices (GEP) Stack Height Analysis

While the Department does allow GEP stacks to be exempt from down-wash impacts, it is recommended that Meridian model for down-wash on all stacks due to the complex terrain/wind of the location and the impact of other stacks or buildings that may not be readily identified as having impacts on stacks.

Section 5.8 NAAQS Attainment Demonstration

The use of H_2S short term value and peak annual values are acceptable for PSD increments and older NAAQS; however, they should not be used for newer NAAQS. Follow the averaging times and percentile values as established in NAAQS & NDAAQS.

Section 6.1

The draft modeling protocol references the FLAG 2000 document, the newer 2010 revision should be used.

Table 8—Class I Areas PSD Increments and Significant Impact Levels are missing the $PM_{2.5}$ levels (see discussion in Section 4.2 PSD Increments).

Section 6.2

At the time the *Site Specific Modeling Guidance* was issued for Meridian, the NPS did not have a specified grid for use within the park; consultation with the Park Service on receptor grid may be advisable.

Past Class I modeling conducted by the NDDoH has included a 2000 m grid within the Class I boundaries; it is anticipated that given the proximity of the Davis Refinery to the Theodore Roosevelt NP-South Unit, that the standard receptor grid will be of finer resolution than the 2000 m standard Class I grid. Should Meridian's receptor grid end before covering the Class I areas or be of a coarser resolution than 2000 m, Meridian should use 2000 m or finer grid with in the Class I boundaries.

For ozone and ammonia background Meridian should contact the Department for those background values, rather than the FLM. Meridian may contact the FLM about the modeling protocol if it so chooses; however the Department prefers that questions be directed to us first for us to contact the FLM. This is to streamline the process and avoid conflicting answers to questions. Often time issues that arise during source modeling have come up before and the FLM and Department have resolved the issue/question.

Section 6.3 Visibility Impactions Modeling Using VISCREEN

Plume-rise (plume-blight) visibility models will be required if wet cooling towers are to be used at the facility. Modeling AQRVs in accordance with FLAG (2010) is also recommended. The FLAG document has procedures for modeling diffused/uniform haze.

Other

The protocol does not discuss how compliance with the *Policy For The Control Of Hazardous Air Pollutant Emissions In North Dakota (Air Toxics Policy)* will be demonstrated. Petroleum refineries are known to emit hazardous air pollutants and modeling for compliance with the *Air Toxics Policy* is required for a completed permit application. It is our understanding that selective catalytic reduction (SCR) will be used to control NOx emissions from certain heaters at the facility. Ammonia slip is inevitable when using SCR; therefore, ammonia emissions must be quantified and assessed in the air toxics modeling analysis.

Secondary impacts for $PM_{2.5}$ should also be considered; specifically Case 3—Primary and Secondary Impactions of the May 20, 2014 EPA Guidance for $PM_{2.5}$ Permit Modeling by Stephen Page.

As mentioned to you previously, in addition to air quality issues the Department has significant concerns regarding the ability of Meridian to obtain an adequate water supply to operate a full-scale refinery at the proposed location. We advise you to contact the appropriate agencies including the Division of Water Quality as soon as possible to address this issue.

Summary

Potential emissions from the proposed facility appear to be very low for a full-scale refinery with a capacity of 55,000 barrels per day. Although minimizing emissions is a goal of the Department, we have concerns as to whether the facility can achieve and maintain emissions at a minor source level. Prior to continuing with a modeling analysis of the Davis Refinery, it is highly recommended that Meridian re-evaluate the emissions estimates to verify that the emissions from the facility will be able to remain below PSD major source thresholds. All emissions estimates must be guaranteed and all technologies must have been successfully demonstrated in practice on a long-term basis. These steps will help ensure proper permitting of the facility and compliant operations.

Questions regarding dispersion modeling can be directed to Rheanna Kautzman at 701-328-5188 or rkautzman@nd.gov. Questions regarding emissions estimates can be directed to David Stroh at 701-328-5188 or destroh@nd.gov. Any other questions can be directed to me at 701-328-5188 or cthorstenson@nd.gov.

Sincerely,

Craig D. Thorstenson
Environmental Engineer
Permitting Supervisor
Division of Air Quality

CDT/RK/DES:saj

xc: David Glatt, Chief, Environmental Health Section
Karl Rockeman, Director, Division of Water Quality