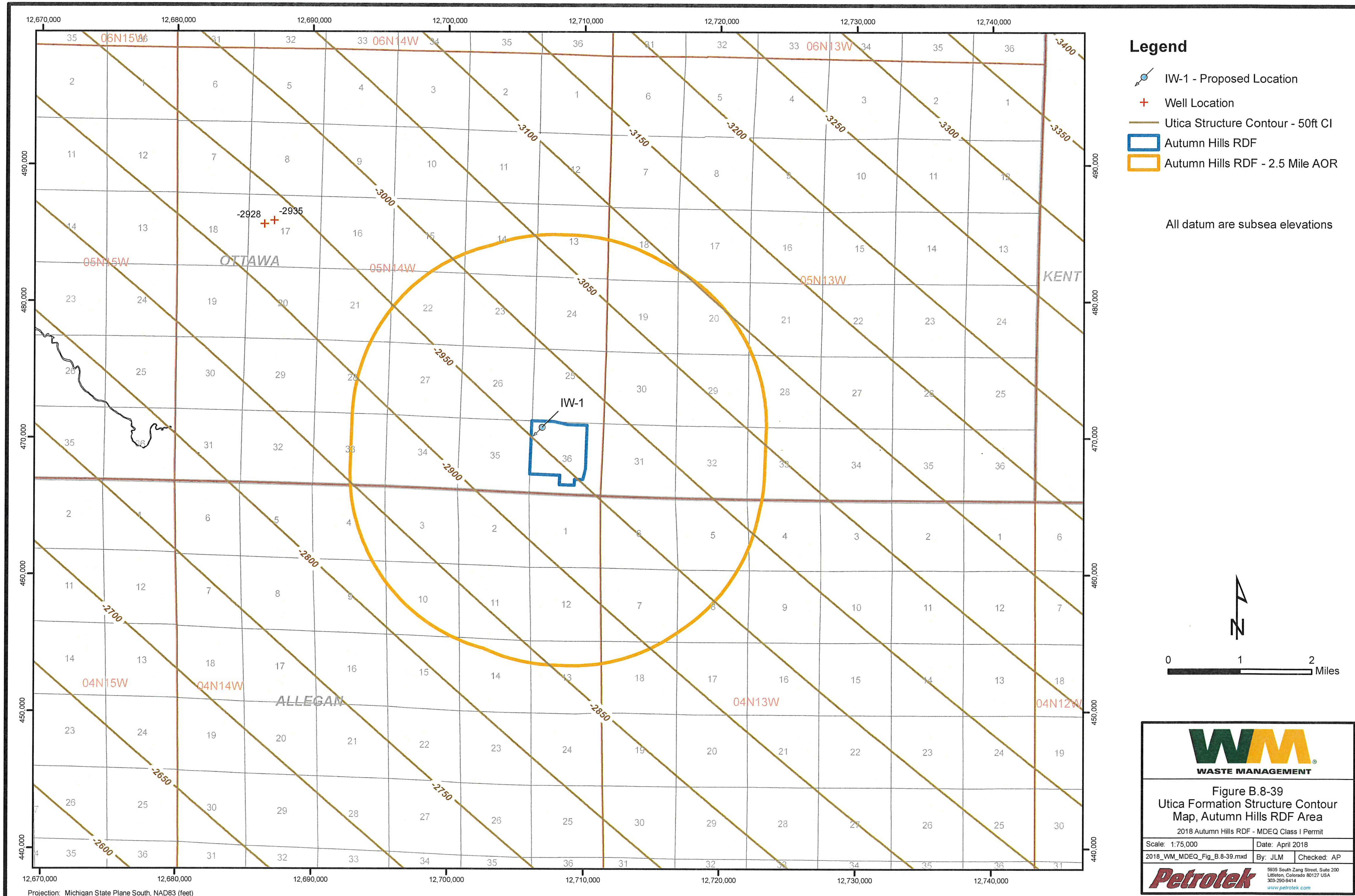
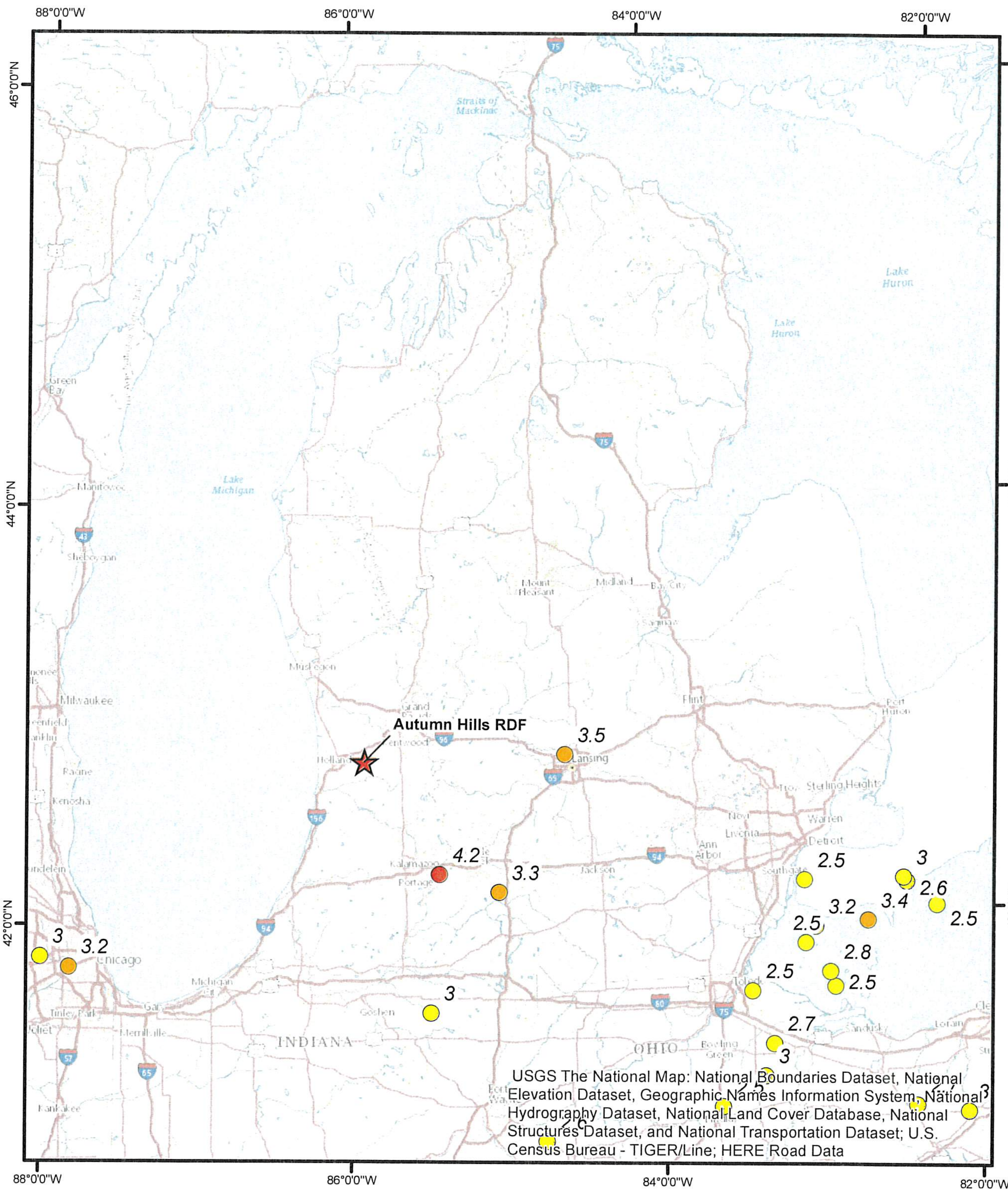


Legend
IW-1 - Proposed Location
Well Location
Utica Structure Contour - 50ft CI
Autumn Hills RDF
Autumn Hills RDF - 2.5 Mile AOR
All datum are subsea elevations
IW-1
-2928
-2935
OTTAWA
ALLEGAN
KENT
06N15W
06N14W
06N13W
05N15W
05N14W
05N13W
04N15W
04N14W
04N13W
04N12W
-2600
-2650
-2700
-2750
-2800
-2850
-2900
-2950
-3000
-3050
-3100
-3150
-3200
-3250
-3300
-3350
-3400
0
1
2
Miles
N
WASTE MANAGEMENT
Figure B.8-39
Utica Formation Structure Contour Map, Autumn Hills RDF Area
2018 Autumn Hills RDF - MDEQ Class I Permit
Scale: 1:75,000
Date: April 2018
2018_WM_MDEQ_Fig_B.8-39.mxd
By: JLM
Checked: AP
Petrotek
5935 South Zang Street, Suite 200
Littleton, Colorado 80127 USA
303-290-9414
www.petrotek.com
Projection: Michigan State Plane South, NAD83 (feet)



Legend

Autumn Hills RDF

mag

- 1.10 - 1.50
- 1.51 - 2.00
- 2.01 - 3.00
- 3.01 - 4.00
- 4.01 - 5.01

N

0 25 50 Miles

Projection: Michigan State Plane South, NAD83 (feet)

WASTE MANAGEMENT

Figure B.8-40
Location of Earthquakes Detected in Region Since 1900 to Present
2018 Autumn Hills RDF - MDEQ Class I Permit

Scale: 1:3,000,000	Date: April 2018
2018_WM_MDEQ_Fig_B.8-40.mxd	By: JLM / Checked: AP

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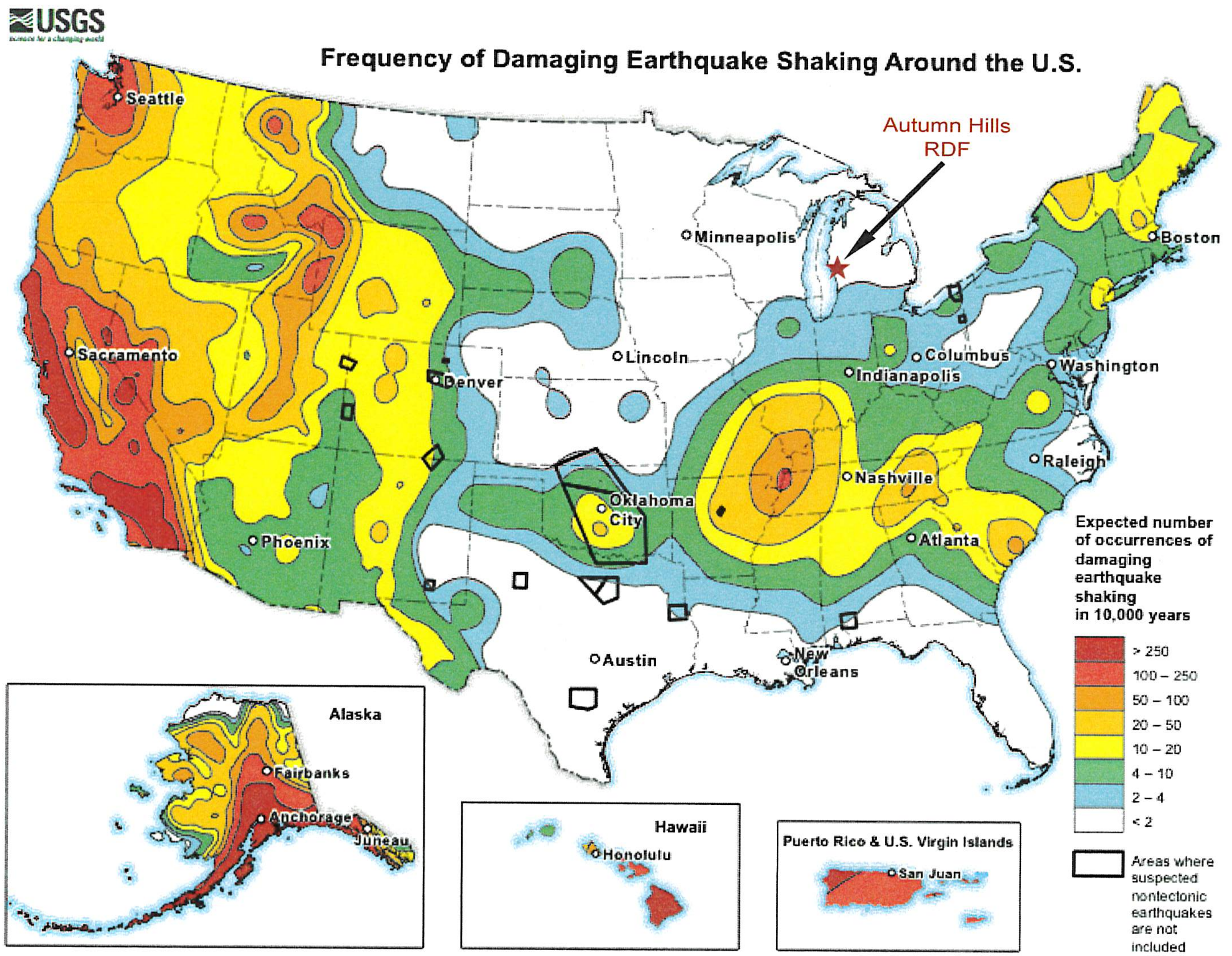
Littleton, Colorado 80127 USA
303-290-9414
www.petrotek.com



WASTE MANAGEMENT

Figure B.8-41
Location of Potential Induced Seismicity Areas in the United States

2018 Autumn Hills RDF - MDEQ Class I Permit

Scale: NTS	Date: April 2018
2018_WM_MDEQ_Fig_B.8-41.ai	By: JLM · Checked: AP

Petrotek
5935 South Zang Street, Suite 200
Littleton, Colorado 80127 USA
303-290-9414
www.petrotek.com

B.9 Chemical, physical and bacteriological characterizations of the waste stream before and after treatment and/or filtration. Include a characterization of the compatibility of the injectate with the injection zone and the fluid in the injection zone along with a characterization of the potential for multiple waste streams to react in the well bore or in the injection zone.

Injectate Characteristics

Well IW-1 will inject non-hazardous fluids generated on-site from the leachate and gas condensate collection systems. As necessary, storm water, surface water run-off, and/or fluids derived from or necessary for IW-1 operation and maintenance may also be injected. Fluids will be transferred by flowline from the capture system units to an above ground storage tank where the leachate, gas condensate, and fluids will be comingled prior to injection. The leachate collection system is anticipated to constitute the majority of the total fluid volume.

Landfill leachate is generated when precipitation contacts the solid waste in the landfill's active disposal area. As this precipitation migrates downward through the waste mass, it dissolves soluble materials (or leaches) and mixes with other liquids contained within the waste or generated as part of the degradation process. Landfill leachate is comprised of approximately 98% water, along with small levels of dissolved salts (sodium, chloride, bicarbonate, and potassium), organics, and other nutrients (Ammonia, BOD). Naturally occurring bacteria consume organic components of solid waste, generating landfill gas composed of 60% methane, 40% carbon dioxide.

This gas is collected using a compressor applied to the landfill-wide gas collection system wherein the landfill gas flows, under vacuum, through the header piping toward the compressor with the piping getting successively larger in diameter, managing larger combined volumes closer to the compressor. The compressor sends the gas for treatment in an open flare or for beneficial reuse in a Gas to Energy Facility. Condensate from this system accumulates within the header piping, and gravity flows to individual collection points or drains through barometric driplegs into the leachate management system. The landfill gas condensate is pumped through the same common force main used to manage the landfill leachate and comingles within the collection system.

Under the Autumn Hills RDF Operating License, total leachate volume is recorded on a monthly basis and water quality on a quarterly basis. Fluid to be injected is collected at the leachate collection sumps in each cell, then is transferred by flowline or truck to a leachate holding tank. In addition to water from the leachate collection system, liquids will also be collected from the landfill gas condensate collection system. A single sample is collected from the composite stream on a quarterly basis, and analyzed for the parameters per the Landfill Operating License requirements.

Leachate is currently being managed under agreement with SET Environmental through transportation by truck for disposal at their commercial facility in Grand Rapids. The Commercial Waste Facility discharges their combined waste volume to the City of Grand Rapids POTW. Approximately six 13,000 gallon loads per day (Monday-Friday) are hauled for offsite disposal. Leachate analyses performed in November 2016 and October 2016 are summarized in Tables B.9-1 and B.9-2, respectively, which are provided at the end of this section. These analyses show that these leachate samples contain almost no detected organic compounds. TDS values from leachate sampling data from 2012 to 2017 varied from 6,980 mg/L to 14,800 mg/L, with the 2016 sample exhibiting a TDS value of 7,200 mg/L. Table B.9-3 presents the most recent leachate analyses (prior to permit application preparation) performed in February 2018. This sample exhibited a TDS value of 6,060 mg/L.

Compatibility and plugging problems encountered due to injection of non-hazardous landfill leachate and gas condensate are possible due to particulate matter, which could cause decreased flow capacity. Screens or filters may be used to condition fluids if needed. Due to the composition of the fluid to be injected and landfill origin, periodic biocide treatments may be instituted as needed to prevent the establishment of bacterial plugging issues. Also, it is possible that the concentration of iron within injectate could lead to precipitation issues within tubing, pipe, or the injection formation, so implementation of a system to prevent plugging or treat iron may be required. Such solids, compatibility, or bacterial problems, if they do occur, would not be a containment issue, but would be an operations issue. If plugging occurred and was not remedied, the operator could reduce injection rates so that maximum pressure limits are not exceeded. To sustain rates if such a situation develops, periodic stimulations may be required, but would be accomplished within regulatory requirements. Only relatively low suspended solids fluids derived from the Autumn Hills RDF operations will be injected in the well.

Table B.9-1. Leachate Analysis, Select Parameters, Autumn Hills RDF, November 2016

SAMPLENAME	SAMPNUM	SAMPDATE	STIME	MATRIX	REFER_CITATION	PARAMETER	CASNUM	BATCH	QCBATCH	RUNDATE	CHEM	REPLIMIT	RESULT	UNIT
Leachate	1611447-01	11/22/2016	08:00:00	Water	USEPA-6020A	Aluminum, Dissolved	7429-90-5	6K30029	1612484	11/30/2016	MSB	0.10	0.40	mg/L
Leachate	1611447-01	11/22/2016	08:00:00	Water	SM 2320 B-2011	Alkalinity, Bicarbonate		6L02006	1612669	12/1/2016	JLB	20	9500	mg/L
Leachate	1611447-01	11/22/2016	08:00:00	Water	SM 2320 B-2011	Alkalinity, Total		6L02005	1612672	12/1/2016	JLB	20	11000	mg/L
Leachate	1611447-01	11/22/2016	08:00:00	Water	USEPA-6020A	Arsenic, Dissolved	7440-38-2	6K30029	1612484	11/30/2016	MSB	0.010	0.26	mg/L
Leachate	1611447-01	11/22/2016	08:00:00	Water	USEPA-6010C	Calcium, Dissolved	7440-70-2	6K29007	1612483	11/29/2016	KLV	5.0	140	mg/L
Leachate	1611447-01	11/22/2016	08:00:00	Water	USEPA-6020A	Cadmium, Dissolved	7440-43-9	6K30029	1612484	11/30/2016	MSB	0.00020	<0.00020	mg/L
Leachate	1611447-01	11/22/2016	08:00:00	Water	SM 4500-Cl E-2011	Chloride	16887-00-6	6L02049	1612559	11/28/2016	LMA	50	3100	mg/L
Leachate	1611447-01	11/22/2016	08:00:00	Water	USEPA-6020A	Chromium, Dissolved	7440-47-3	6K30029	1612484	11/30/2016	MSB	0.010	0.37	mg/L
Leachate	1611447-01	11/22/2016	08:00:00	Water	EDTA TriMatrix In-house Method	EDTA	60-00-4	6L02025	1612646	12/2/2016	JLB	2.5	34	mg/L
Leachate	1611447-01	11/22/2016	08:00:00	Water	USEPA-6010C	Iron, Dissolved	7439-89-6	6K29007	1612483	11/29/2016	KLV	0.20	42	mg/L
Leachate	1611447-01	11/22/2016	08:00:00	Water	USEPA-6010C	Potassium, Dissolved	7440-09-7	6K29007	1612483	11/29/2016	KLV	1.0	890	mg/L
Leachate	1611447-01	11/22/2016	08:00:00	Water	USEPA-6010C	Magnesium, Dissolved	7439-95-4	6K29007	1612483	11/29/2016	KLV	5.0	160	mg/L
Leachate	1611447-01	11/22/2016	08:00:00	Water	USEPA-6020A	Manganese, Dissolved	7439-96-5	6K30029	1612484	11/30/2016	MSB	0.010	0.90	mg/L
Leachate	1611447-01	11/22/2016	08:00:00	Water	USEPA-6010C	Sodium, Dissolved	7440-23-5	6K29007	1612483	11/29/2016	KLV	5.0	2800	mg/L
Leachate	1611447-01	11/22/2016	08:00:00	Water	USEPA-6020A	Nickel, Dissolved	7440-02-0	6K30029	1612484	11/30/2016	MSB	0.010	0.69	mg/L
Leachate	1611447-01	11/22/2016	08:00:00	Water	SM 4500-NH3 G-2011	Nitrogen, Ammonia	7664-41-7	6L05025	1612696	12/2/2016	LEW	100	2000	mg/L
Leachate	1611447-01	11/22/2016	08:00:00	Water	SM 4500-NO3 F-2011	Nitrogen, Nitrate+Nitrite	14797-55-8	6L12052	1612951	12/7/2016	JTW	0.10	1.0	mg/L
Leachate	1611447-01	11/22/2016	08:00:00	Water	SM 4500-P E-2011	Phosphorus, Total	7723-14-0	6L01012	1612519	11/29/2016	ASC	0.100	7.55	mg/L
Leachate	1611447-01	11/22/2016	08:00:00	Water	SM 2540 C-2011	Residue, Dissolved @ 180° C		6K28020	1612526	11/28/2016	MAD	833	7200	mg/L
Leachate	1611447-01	11/22/2016	08:00:00	Water	SM 4500-S2 D-2011	Sulfide, Total	18496-25-8	6K28048	1612543	11/28/2016	JTW	0.50	5.5	mg/L
Leachate	1611447-01	11/22/2016	08:00:00	Water	USEPA-6020A	Zinc, Dissolved	7440-66-6	6K30029	1612484	11/30/2016	MSB	0.10	0.16	mg/L
Leachate	1611447-01	11/22/2016	08:00:00	Water	USEPA-6020A	Lead, Dissolved	7439-92-1	6K30029	1612484	11/30/2016	MSB	0.010	<0.010	mg/L
Leachate	1611447-01	11/22/2016	08:00:00	Water	SM 4500-H B-2011	pH		6K28069	1612556	11/28/2016	AMM	1.0	8.4	pH Units
Leachate	1611447-01	11/22/2016	08:00:00	Water	SM 2540 D-2011	Residue, Suspended		6K28003	1612504	11/28/2016	MAD	49.5	180	mg/L
Leachate	1611447-01	11/22/2016	08:00:00	Water	SM 4500-SO4 E-2011	Sulfate	14808-79-8	6L03014	1612699	11/30/2016	LMA	5.0	6.5	mg/L

Table B.9-2. Leachate Analysis, Organic and Select Inorganic Parameters, Autumn Hills RDF, October 2016

Sample Name	Sample Date	Chemical Name	Report Result Value	Report Result Units	Reporting Limit	Detect Flag
LMP01	10/25/2016	1,1,1,2-Tetrachloroethane	<14	UG/L	14	N
LMP01	10/25/2016	1,1,1-Trichloroethane	<33	UG/L	33	N
LMP01	10/25/2016	1,1,2,2-Tetrachloroethane	<8.4	UG/L	8.4	N
LMP01	10/25/2016	1,1,2-Trichloroethane	<9.2	UG/L	9.2	N
LMP01	10/25/2016	1,1-Dichloroethane	<15	UG/L	15	N
LMP01	10/25/2016	1,1-Dichloroethene	<12	UG/L	12	N
LMP01	10/25/2016	1,2,3-Trichloropropane	<36	UG/L	36	N
LMP01	10/25/2016	1,2-DICHLOROBENZENE	<32	UG/L	32	N
LMP01	10/25/2016	1,2-Dichloroethane	<8.4	UG/L	8.4	N
LMP01	10/25/2016	1,2-Dichloropropane	<29	UG/L	29	N
LMP01	10/25/2016	1,4-Dichlorobenzene	<34	UG/L	34	N
LMP01	10/25/2016	Benzene	<16	UG/L	16	N
LMP01	10/25/2016	Bromodichloromethane	<16	UG/L	16	N
LMP01	10/25/2016	Bromoform	<10	UG/L	10	N
LMP01	10/25/2016	BROMOMETHANE	<28	UG/L	28	N
LMP01	10/25/2016	Carbon Tetrachloride	<11	UG/L	11	N
LMP01	10/25/2016	Chloride	2770	MG/L	14.1	Y
LMP01	10/25/2016	Chlorobenzene	<30	UG/L	30	N
LMP01	10/25/2016	Chloroethane	<13	UG/L	13	N
LMP01	10/25/2016	Chloroform	<14	UG/L	14	N
LMP01	10/25/2016	CHLOROMETHANE	<14	UG/L	14	N
LMP01	10/25/2016	CIS-1,2-DICHLOROETHENE	<32	UG/L	32	N
LMP01	10/25/2016	cis-1,3-Dichloropropene	<14	UG/L	14	N
LMP01	10/25/2016	Dibromochloromethane	<13	UG/L	13	N
LMP01	10/25/2016	DIBROMOMETHANE	<16	UG/L	16	N
LMP01	10/25/2016	Ethylbenzene	<30	UG/L	30	N
LMP01	10/25/2016	IODOMETHANE	<12	UG/L	12	N
LMP01	10/25/2016	Iron	39.2	MG/L	0.020	Y
LMP01	10/25/2016	Methylene Chloride	<18	UG/L	18	N
LMP01	10/25/2016	pH (Field)	8.05	S.U.		Y
LMP01	10/25/2016	Residue, Filterable (TDS)	10500	MG/L	80.0	Y
LMP01	10/25/2016	Specific Conductance (Field)	10200	UMHOS/CM		Y
LMP01	10/25/2016	Styrene	<29	UG/L	29	N
LMP01	10/25/2016	Sulfate	<17.5	MG/L	17.5	N
LMP01	10/25/2016	Temperature (Field Test)	19.6	DEG C		Y
LMP01	10/25/2016	Tetrachloroethene	<14	UG/L	14	N
LMP01	10/25/2016	Toluene	55	UG/L	20	Y
LMP01	10/25/2016	Total Inorganic Nitrogen	1920	MG/L	0.020	Y
LMP01	10/25/2016	trans-1,2-Dichloroethene	<36	UG/L	36	N
LMP01	10/25/2016	trans-1,3-Dichloropropene	<15	UG/L	15	N
LMP01	10/25/2016	Trichloroethene	<18	UG/L	18	N
LMP01	10/25/2016	Trichlorofluoromethane	<35	UG/L	35	N
LMP01	10/25/2016	Vinyl Chloride	<36	UG/L	36	N
LMP01	10/25/2016	Xylenes (total)	26	UG/L	26	Y

Table B.9-3. Leachate Analysis, Autumn Hills RDF, February 2018

Sample Name	Sample Date	Chemical Name	Report Result Value	Report Result Units	Reporting Limit	Detect Flag
Matrix: Leachate (Date Collected: 02/21/2018; Dae Received: 02/22/2018)						
	Method: 8260C - Volatile Organic Compounds by GC/MS					
	2/23/2018	1,1-Dichloroethylene	ND	ug/L	5.8	
	2/23/2018	1,1-Dichloroethane	ND	ug/L	4.2	
	2/23/2018	1,4-Dichlorobenzene	ND	ug/L	17	
	2/23/2018	Benzene	ND	ug/L	8.2	
	2/23/2018	Carbon Tetrachloride	ND	ug/L	5.4	
	2/23/2018	Chlorobenzene	ND	ug/L	15	
	2/23/2018	Chloroform	ND	ug/L	6.8	
	2/23/2018	Tetrachloroethylene	ND	ug/L	7.2	
	2/23/2018	Trichloroethylene	ND	ug/L	9.2	
	2/23/2018	Vinyl Chloride	ND	ug/L	18	
	Method: 6010C - Metals (ICP)					
	2/23/2018	Barium	0.25	mg/L	0.005	
	2/23/2018	Potassium	421000	ug/L	100	
	2/23/2018	Sodium	1290	mg/L	1.6	
	Method: 6020A - Metals (ICP/MS)					
	2/28/2018	Arsenic	314	ug/L	2.7	
	2/28/2018	Lead	7.1	ug/L	1.7	
	General Chemistry					
	3/2/2018	Ammonia, distilled	1170	mg/L as N	100	
	2/27/2018	Nitrate-Nitrite	0.07	mg/L as N	0.05	
	3/7/2018	Alkalinity, Bicarbonate	6450	mg/L	10	
	3/7/2018	Alkalinity, Total	6450	mg/L	5	
	3/25/2018	Total Dissolved Solids	6060000	ug/L	40000	
	2/27/2018	Chloride	1450000	ug/L	14100	
	2/23/2018	Total Organic Carbon	1010000	ug/L	8680	
	2/27/2018	Flashpoint	>180.0	Degrees F	50	
	2/26/2018	Cyanide, Reactive	ND	mg/L	10	
	2/26/2018	Sulfide, Reactive	ND	mg/L	10	
	2/26/2018	Specific Gravity	1	g/mL	0.1	
	3/5/2018	Total Inorganic Nitrogen	1170	mg/L	0.02	
	Method: Field Sampling					
	2/21/2018	Field pH	8.08	SU	None	
	2/21/2018	Field EH/ORP	-82	millivolts	None	
	2/21/2018	Field Conductivity	9580	umhos/cm	None	
	2/21/2018	Field Temperature	13.4	Degrees C	None	
Matrix: Water (Date Collected: 02/21/2018; Dae Received: 02/22/2018)						
	Method: 8260C - Volatile Organic Compounds by GC/MS					
	2/23/2018	1,1-Dichloroethylene	ND	ug/L	1	
	2/23/2018	1,1-Dichloroethane	ND	ug/L	1	
	2/23/2018	1,4-Dichlorobenzene	ND	ug/L	1	
	2/23/2018	Benzene	ND	ug/L	1	
	2/23/2018	Carbon Tetrachloride	ND	ug/L	1	
	2/23/2018	Chlorobenzene	ND	ug/L	1	
	2/23/2018	Chloroform	ND	ug/L	1	
	2/23/2018	Tetrachloroethylene	ND	ug/L	1	
	2/23/2018	Trichloroethylene	ND	ug/L	1	
	2/23/2018	Vinyl Chloride	ND	ug/L	5	

B.10 Information to characterize the proposed injection zone, including:

- **A. The geological name of the stratum or strata making up the injection zone and the top and bottom depths of the injection zone.**
- **B. An isopach map showing thickness and areal extent of the injection zone**
- **C. Lithology, grain mineralogy and matrix cementing of the injection zone.**
- **D. Effective porosity of the injection zone including the method of determination.**
- **E. Vertical and horizontal permeability of the injection zone and the method used to determine permeability. Horizontal and vertical variations in permeability expected within the area of influence.**
- **F. The occurrence and extent of natural fractures and/or solution features within the area of influence.**
- **G. Chemical and physical characteristics of the fluids contained in the injection zone and fluid saturations.**
- **H. The anticipated bottom hole temperature and pressure of the injection zone and whether these quantities have been affected by past fluid injection or withdrawal.**
- **I. Formation fracture pressure, the method used to determine fracture pressure and the expected direction of fracture propagation.**
- **J. The vertical distance between the top of the injection zone from the base of the lowest fresh water strata.**
- **K. Other information the applicant believes will characterize the injection zone.**

Items A-C are detailed in Section B.8. Items D-K will be verified during drilling and testing of IW-1. Literature data available to characterize formations has been cited in previous sections. Available data are summarized below.

A. The geological name of the stratum or strata making up the injection zone and the top and bottom depths of the injection zone.

The proposed injection zone includes the interval from (deepest to shallowest) the Mt. Simon Sandstone to the Trempealeau Formation. WM only intends to complete the Mt. Simon as the injection interval. The table below provides estimated top/bottom depths in feet below ground level (GL) and feet below mean sea level (BSL) for this formation.

Formation	IW-1 Est. Depth to Top, from GL (ft)	IW-1 Est. Depth to Top, ft BSL
Ground Level (feet ASL)	703	---
Glacial Drift	0	-703
Marshall Sandstone	160	-543
Coldwater Shale	220	-483
Ellsworth Shale	950	247
Antrim Shale	1,510	807
Traverse Group	1,610	907
Dundee Limestone	1,930	1,227
Detroit River Group	2,050	1,347
Bass Island Group	2,410	1,707
Salina Group	2,485	1,782
Niagara Group	3,245	2,542
Clinton Group	3,295	2,592
Cabot Head Shale	3,345	2,642
Manitoulin Dolomite	3,365	2,662
Undifferentiated Upper Cincinnatian	3,385	2,682
Utica Shale	3,663	2,960
Trenton Formation	3,853	3,150
Black River Formation	4,153	3,450
Prairie du Chien Group	4,338	3,635
Trempealeau Formation	4,893	4,190
Franconia Formation	5,103	4,400
Dresbach Formation	5,228	4,525
Eau Claire Formation	5,373	4,670
Mt. Simon Sandstone	5,578	4,875
Precambrian Granite Wash	6,570	5,867
Precambrian basement	6,600	5,897

B. An isopach map showing thickness and areal extent of the injection zone

Figures B.8-8 and B.8-27 are regional and local isopachs of the Mt. Simon Sandstone, respectively. Figures B.8-10 and B.8-29 are regional and local isopachs of the Eau Claire, respectively. Figures B.8-12 and B.8-31 are regional and local isopachs of the Galesville (Dresbach) Formation, respectively. Figure B.8-33 presents a local isopach of the Franconia Formation. Figures B.8-13 and B.8-35 are regional and local isopachs of the Trempealeau Formation, respectively. Figures B.8-14 and B.8-36 present regional and local isopachs of the Prairie du Chein Group. An isopach map for the Trenton-Black River is presented in Cohee (1945) and indicates a total thickness of 400-500 feet, which compares well to the total thickness of 485 feet for these formations presented in the table above. In total, the injection zone from the base of the Mt. Simon to the base of the Utica Shale is laterally pervasive and is approximately 2,700 feet thick in the Autumn Hills RDF area.

It is noted that Waste Management of Michigan, Inc., only intends to use the Mt. Simon injection interval as an open hole completion for the proposed IW-1 well.

C. Lithology, grain mineralogy and matrix cementing of the injection zone.

See Section B.8 for detailed lithologic information concerning the Injection Zone formations.

D. Effective porosity of the injection zone including the method of determination.

See Section B.8 for detailed information concerning the effective porosity of the injection zone formations and method of determination. Core data available for the formations in the injection zone are presented in Section B.8.

The injection zone includes the Mt. Simon, Eau Claire, Dresbach/Galesville, Franconia, Trempealeau, Prairie du Chein, St. Peter/Glenwood and Black River/Trenton formations. The Mt. Simon is the injection interval that will be completed, open hole, and into which injection will take place. The overlying formations constitute the remainder of the injection zone, and these formations offer arrestment capabilities. The following summarizes porosity information pertaining to the Formations of the Munsing Group and Trempealeau Formation, noting that the Mt. Simon information is also included in Section B.8. Information pertaining to the Prairie du Chein Group and St. Peter/Glenwood Formations is presented in Section B.8.

<u>Injection Zone: Mt. Simon Porosity Range</u>

As indicated in Section B.8.2.2.2, the Mt. Simon injection interval is well characterized by local core data that present local porosity information. Cores were taken from the Mt. Simon in the Warner-Lambert No. 5 well from 5,200-5,231 ft BGL and BASF Well No. 1 from 5,300-5,335 and 5,516-5,576 BGL. These wells are located west of the Site area. Mt. Simon porosity information obtained from the Warner-Lambert No. 5 core indicates the horizontal plug porosity varies from 14-19% in a 30 ft interval of the Mt. Simon, which is generally representative of the anticipated porosity range at Autumn Hill RFD's proposed IW-1. Formation test results for the BASF well obtained during well testing show an effective porosity of 12.2%, which is lower but generally consistent with that obtained by core at the Warner Lambert No. 5 well.

Injection Interval: Eau Claire, Dresbach/Galesville, Franconia, and Trempealeau Formations Porosity Ranges

The following information addressed porosity of formations above the Mt. Simon, and is based on wireline log data from the Consumers Energy Generating Station (Mirant) well IW-1.

Eau Claire Porosity Range: Wireline data from the Mirant IW-1 was evaluated for the 180 foot thick Eau Claire Formation. Based on the high gamma ray readings throughout the entire thickness of this interval, the Eau Claire is composed of almost entirely shale and therefore would be expected to have very little effective porosity. The average gamma ray values for the entire interval average approximately 155 GAPI.

The average neutron porosity in the Eau Claire is approximately 19%, though apparent neutron porosity readings in shale are always significantly higher than actual formation porosity. This is due to the fact that shales contain clays that have a significant amount of bound water which increases the hydrogen index of the formation. As the neutron tool is sensitive to the amount of hydrogen atoms in a formation, this results in higher neutron porosity data due to the shale effect or bound-water effect. Therefore, there is likely little to no effective porosity in the Eau Claire Formation. As such, while included in the Injection Zone, the Eau Claire serves as an arrestment interval above the Mt. Simon and would impede vertical fluid flow.

Additional information from core data is presented in Section B.8 in Tables B.8.6a and B.8.6b.

Dresbach/Galesville Porosity Range: Wireline data from the Mirant IW-1 was evaluated for the 120 foot thick Dresbach/Galesville interval. The Dresbach/Galesville is primarily described as a silica cemented sandstone with occasional shale lamination (Sections B.8.1.3.2 and B.8.2.2.2). Utilizing a gamma ray cutoff of 60 GAPI to evaluate relatively clean sandstone intervals, there is approximately 67 feet of sand with an average neutron porosity of 17.5%, though the potential presence of glauconite (which yields higher gamma ray readings) may impact this cutoff thickness.

Additional information from core data is presented in Section B.8 in Tables B.8.7a and B.8.7b.

Franconia Porosity Range: Wireline data from the Mirant IW-1 was evaluated for the 118 foot thick Franconia Formation. Average neutron porosity across this interval is approximately 17.5%. Additional information for the Franconia is presented in Section B.8.

Trempealeau Porosity Range: Wireline data from the Mirant IW-1 was evaluated for the 199 foot thick Trempealeau Formation. Based on the neutron porosity data, there are 168 feet, 86 feet, and 43 feet of thickness at 8%, 12%, and 15% respectively. Additional information for the Trempealeau is presented in Section B.8.

Trenton/Black River Porosity Range: Core plug data from the Warner-Lambert Well No. 5 indicates that within a core collected from a 20 ft interval exhitibs horizontal plug porosity from 0.005%-0.04%. Additional information for the Trenton is presented in Section B.8.

E. Vertical and horizontal permeability of the injection zone and the method used to determine permeability. Horizontal and vertical variations in permeability expected within the area of influence.

Permeability data for the formations in the injection zone are provided in various tables in Section B.8.

F. The occurrence and extent of natural fractures and/or solution features within the area of influence.

No solution features such as paleokarst are documented in the proposed injection zone at the proposed well location. See B.8 for additional information about injection zone lithologies and structural geology.

G. Chemical and physical characteristics of the fluids contained in the injection zone and fluid saturations.

Fluid samples were obtained during drilling from the IW-1 and IW-2 wells at the Consumers Energy Zeeland Generating Station site less than five miles to the northwest. Reported Mt. Simon TDS values for wells IW-1 and IW-2 were 190,000 mg/L and 220,000 mg/L, respectively.

Additional information is provided in Sections B.7, B.8.2.2.2 and B.8.2.2.3.

H. The anticipated bottom hole temperature and pressure of the injection zone and whether these quantities have been affected by past fluid injection or withdrawal.

The nearest wells that penetrate through the Mt. Simon Sandstone are the Consumers Energy Generating Station wells IW-1 and IW-2 (Mirant wells). Maximum recorded bottomhole temperature from wireline log data was 106° F at a depth of 6,670 ft RKB (6,657 ft BGL) and 122° F at a depth of 6,630 ft RKB (6,618 ft BGL) for the Mirant wells IW-1 and IW-2, respectively.

Reservoir pressure in the Mt. Simon Sandstone is estimated based on data from the Mirant IW-2 well, where an original measured pressure of 2,429.5 psi was recorded at a depth of 5,280 ft RKB (5,267 ft BGL). This is equivalent to a reservoir pressure gradient of approximately 0.46 psi/ft, which is consistent with regional data for the Mt. Simon in this portion of Michigan. Based on an estimated total depth of 6,614 ft RKB (6,600 ft

BGL) and a reservoir pressure gradient of 0.46 psi/ft in the Mt. Simon, estimated bottom hole pressure is estimated to be 3,036 psi.

I. Formation fracture pressure, the method used to determine fracture pressure and the expected direction of fracture propagation.

Well IW-1 will be designed for operation under positive pressure to be supplied by using an injection pump. Although no site specific data are available, the US EPA Region 5 2013 permits for the Consumers Energy IW-1 and IW-2 used an EPA assigned value of 0.725 psi/ft for the fracture gradient of the Mt. Simon injection interval, therefore this value will be used for the Autumn Hills RDF IW-1 well. If injection fluid is assumed to be comprised of a brine with a maximum specific gravity of 1.1 (maximum anticipated average specific gravity of 1.05 plus 0.05 safety margin) that fills the tubing from the surface to a maximum depth of 3,853 feet (estimated top of the injection zone), a maximum wellhead injection pressure of 944 psi is calculated based on this Region 5 assigned gradient and formula presented in the Consumers Energy permits where a value of 14.7 psi is subtracted from the calculated value (3,853 * (0.725-(0.433*1.1))-14.7). The value is conservative since no allowances for tubing friction are included in this calculation. Average injection pressure is expected to be approximately 500 to 800 psi.

Note that the average specific gravity is expected to be in the 1.00 to 1.05 range. The actual maximum pressure exerted by injectate of a 1.05 specific gravity at the top of the injection zone (estimated to be 3,853 feet BGL) is not expected to exceed 1,752 psi, and when adding the requested wellhead injection pressure of 944 psi yields a total downhole pressure of 2,696 psi, which is significantly less than the calculated fracture pressure of 2,793 psi (3,853 ft * 0.725 psi/ft) with friction losses neglected, thus offering a safety margin.

Note that WM only intends to complete the IW-1 well to the Mt. Simon Sandstone with a casing shoe at a depth of approximately 5,600 feet. Therefore, calculations at the shallower depth of 3,853 feet are conservative.

J. The vertical distance between the top of the injection zone from the base of the lowest fresh water strata.

As shown in the table above, the top of the Trenton (top of the injection zone) is over 3,500 feet below the base of the Glacial Drift/Marshall Sandstone USDW interval. As Waste Management of Michigan, Inc., only intends to complete the IW-1 well to the Mt. Simon Sandstone, the top of the Mt. Simon Sandstone is located more than 5,200 feet below the base of the USDW.

K. Other information the applicant believes will characterize the injection zone.

See Section B.8 for additional information.

B.11 Information to characterize the proposed confining zone, including:

A. The geological name of the stratum or strata making up the confining zone and the top and bottom depths of the confining zone.
B. An isopach map showing thickness and areal extent of the confining zone
C. Lithology, grain mineralogy and matrix cementing of the confining zone.
D. Effective porosity of the confining zone including the method of determination.
E. Vertical and horizontal permeability of the confining zone and the method used to determine permeability. Horizontal and vertical variations in permeability expected within the area of influence.
F. The occurrence and extent of natural fractures and/or solution features within the area of influence.
G. Chemical and physical characteristics of the fluids contained in the confining zone and fluid saturations.
H. Formation fracture pressure, the method used to determine fracture pressure and the expected direction of fracture propagation.
I. The vertical distance between the top of the confining zone from the base of the lowest fresh water strata.
J. Other information the applicant believes will characterize the confining zone.

Items A-C are detailed in Section B.8. Items D-J will be verified during drilling and testing of the IW-1 well. Literature data available to characterize formations has been cited in previous sections. Available data are summarized below.

A. The geological name of the stratum or strata making up the confining zone and the top and bottom depths of the confining zone.

The proposed confining zone is the Utica Shale. The table below provides estimated top/bottom depths in feet below ground level (GL) and feet below mean sea level (BSL) for this formation.

Formation	IW-1 Est. Depth to Top, from GL (ft)	IW-1 Est. Depth to Top, ft BSL
Ground Level (feet ASL)	703	---
Glacial Drift	0	-703
Marshall Sandstone	160	-543
Coldwater Shale	220	-483
Ellsworth Shale	950	247
Antrim Shale	1,510	807
Traverse Group	1,610	907
Dundee Limestone	1,930	1,227
Detroit River Group	2,050	1,347
Bass Island Group	2,410	1,707
Salina Group	2,485	1,782
Niagara Group	3,245	2,542
Clinton Group	3,295	2,592
Cabot Head Shale	3,345	2,642
Manitoulin Dolomite	3,365	2,662
Undifferentiated Upper Cincinnatian	3,385	2,682
Utica Shale	3,663	2,960
Trenton Formation	3,853	3,150
Black River Formation	4,153	3,450
Prairie du Chien Group	4,338	3,635
Trempealeau Formation	4,893	4,190
Franconia Formation	5,103	4,400
Dresbach Formation	5,228	4,525
Eau Claire Formation	5,373	4,670
Mt. Simon Sandstone	5,578	4,875
Precambrian Granite Wash	6,570	5,867
Precambrian basement	6,600	5,897

B. An isopach map showing thickness and areal extent of the confining zone

Figure B.8-16 is a regional isopach and Figure B.8-38 is a local isopach of the Utica Shale. Based on these data, the estimated thickness of the Utica Shale is at least approximately 190 feet and the interval is aerially extensive across the state.

C. Lithology, grain mineralogy and matrix cementing of the confining zone.

See Section B.8 for detailed lithologic information concerning the Confining Zone formation.

D. Effective porosity of the confining zone including the method of determination.

The Utica Shale is composed primarily of silty claystone deposited in a marine environment (Sattler, 2015). Western Michigan University (WMU,1981) reported porosity from cores collected and evaluated for the Consumers Power Company (Mirant Zeeland) Brine Disposal Well No 139 T4N, R15E, as being 1.5-4%; note that the Utica Shale is the confining zone for these nearby permitted Class I wells. The effective porosities for Utica core collected elsewhere in the Michigan Basin indicate that porosity varies from 0.77-5.93% (Sattler, 2015). The Black River/Trenton occurs immediately below the Utica Shale, and core data obtained from the Warner Lambert Well No. 5 for this interval showed a core porosity ranging from 0.5 to 5%. Therefore, core data are available for the Utica Shale and underlying units, that show low formation permeability.

E. Vertical and horizontal permeability of the confining zone and the method used to determine permeability. Horizontal and vertical variations in permeability expected within the area of influence.

As indicated under item B.11-D above, core data are available for the Utica Shale are available at various locations throughout the state (Briggs, 1968, Stattler, 2015). These data indicate that Utica Shale permeabilities of less than 0.5-2.5 md were reported for the "a location in southeastern Michigan" while Utica Shale permeabilities varied from 0.003-89.42 md elsewhere in the state. Note that WMU (1981) indicates the core described by Briggs is actually the Consumers Energy (Mirant Zeeland) well No. 139 located in T 4N R15E, near the Autumn Hills RDF. The Trenton Group at the Warner-Lambert Well No. 5 exhibited a horizontal brine permeability as low as 5.166×10^{-6} md and vertical core plug permeability to injectate as low as 5.2×10^{-6} md. These data suggest that Utica Shale permeability can be highly variable, but is typically low.

F. The occurrence and extent of natural fractures and/or solution features within the area of influence.

No solution features such as paleokarst are documented in the confining zone at the proposed well location. See B.8 for additional information about confining zone lithologies and characteristics.

G. Chemical and physical characteristics of the fluids contained in the confining zone and fluid saturations.

Data specific to confining zone water quality are not available in the vicinity of the Autumn Hills RDF area. A search of the USGS Produced Waters Geochemical Database (USGS 2018) yielded no water quality samples from the Utica Shale, although 13 water quality samples were available for the underlying Trenton Formation. All Trenton samples were greater than 29,900 mg/l TDS, with the majority in excess of 100,000 mg/l TDS. Two samples from the overlying Guelph/Lockport exhibited water quality in excess of 300,000 mg/l TDS. Note that WMU (1981) states that the Utica Shale is not an aquifer, due to lower permeability and porosity.

H. Formation fracture pressure, the method used to determine fracture pressure and the expected direction of fracture propagation.

Well IW-1 will be designed for operation under positive pressure to be supplied by using an injection pump. Although no site specific data are available, the US EPA Region 5 2013 permits for the Consumers Energy IW-1 and IW-2 used an EPA assigned value of 0.725 psi/ft for the fracture gradient of the Mt. Simon injection interval, therefore this value will be used for the Autumn Hills RDF IW-1 well. If injection fluid is assumed to be comprised of a brine with a maximum specific gravity of 1.1 (maximum anticipated average specific gravity of 1.05 plus 0.05 safety margin) that fills the tubing from the surface to a maximum depth of 3,853 feet (estimated top of the injection zone), a maximum wellhead injection pressure of 944 psi is calculated based on this Region 5 assigned gradient and formula presented in the Consumers Energy permits where a value of 14.7 psi is subtracted from the calculated value (3,853 * (0.725-(0.433*1.1))-14.7). The value is conservative since no allowances for tubing friction are included in this calculation. Average injection pressure is expected to be approximately 500 to 800 psi.

Note that the average specific gravity is expected to be in the 1.00 to 1.05 range. The maximum pressure exerted by injectate of a 1.1 specific gravity (that includes the 0.05 safety factor) at the top of the injection zone (estimated to be 3,853 feet BGL) is not likely to exceed 1,835 psi, and when adding the requested wellhead injection pressure of 944 psi yields a total downhole pressure of 2,779 psi, which is still below the calculated fracture pressure of 2,793 psi (3,853 ft * 0.725 psi/ft) with friction losses neglected, thus offering a safety margin.

Note that WM only intends to complete the IW-1 well to the Mt. Simon Sandstone with a casing shoe at a depth of approximately 5,600 feet. Therefore, calculations at the shallower depth of 3,853 feet are conservative.

I. The vertical distance between the top of the confining zone from the base of the lowest fresh water strata.

As shown in the table above, the top of the Utica Shale (top of the confining zone) is over 3,300 feet below the base of the Glacial Drift/Marshall Sandstone USDW interval.

J. Other information the applicant believes will characterize the confining zone.

See Section B.8 for additional information.

B.12 Information demonstrating injection of liquids into the proposed zone will not exceed the fracture pressure gradient and information showing injection into the proposed geological strata will not initiate fractures through the confining zone. Information showing the anticipated dispersion, diffusion and/or displacement of injected fluids and behavior of transient pressure gradients in the injection zone during and following injection.

Maximum Injection Pressure

Well IW-1 will be designed for operation under positive pressure to be supplied by using an injection pump. Although no site specific data are available, the US EPA Region 5 2013 permits for the Consumers Energy IW-1 and IW-2 used an EPA assigned value of 0.725 psi/ft for the fracture gradient of the Mt. Simon, therefore this value will be used at Autumn Hills. If a safety factor of 0.05 is included (1.05 + 0.05 = 1.1),so that the injection fluid is assumed to be comprised of a brine with a maximum specific gravity of 1.1 that fills the tubing from the surface to a maximum depth of 3,853 feet (estimated top of the injection zone), a maximum wellhead injection pressure of 944 psi is calculated based on a Region 5 assigned gradient and formula presented in the nearby Consumers Energy permits where a value of 14.7 psi is subtracted from the calculated value (944 psi = (3,853 *(0.725-(0.433*1.1))-14.7). The value is conservative since no allowances for tubing friction are included in this calculation. Average injection pressure is expected to be approximately 500 to 800 psi.

Note that the average specific gravity is expected to be in the 1.00 to 1.05 range. The maximum pressure exerted by injectate of a 1.05 specific gravity at the top of the injection zone (estimated to be 3,853 feet BGL) is not likely to exceed 1,752 psi, and when adding the requested wellhead injection pressure of 944 psi yields a total downhole pressure of 2,696 psi, which is significantly less than the calculated bottomhole fracture pressure of 2,793 psi (3,853 ft * 0.725 psi/ft) with friction losses neglected, thus offering a safety margin.

Average Rates, Volumes and Pressures

The range of injection rates and pressures is expected to fluctuate depending on the demands of the system along with variables related to the well and reservoir conditions. Operational injection rates are expected to average 50 gpm, with a maximum rate of 150 gpm. The estimated annual volume is not expected to exceed 26,280,000 gallons/year, with an average daily volume of 72,000 gallons (50 gpm) and maximum expected daily volume of 216,000 gallons (150 gpm). Table B.12-1 presents representative historic leachate generation information that reflects anticipated injectate volumes.

TABLE B.12-1. ANNUAL LEACHATE VOLUMES, AUTUMN HILLS RDF, 2013 TO 2017

Year	Volume (gallons)
2013	13,083,891
2014	17,151,000
2015	19,427,000
2016	19,042,900
2017	20,228,231

The well is to be operated, and operating data will be reported, according to the requirements presented in Table B.12-2.

TABLE B12-2. OPERATING, MONITORING, AND REPORTING REQUIREMENTS, AUTUMN HILLS RDF WELL IW-1

Characteristic	Value	Minimum Monitoring Frequency [2]	Minimum Reporting Frequency
Injection Rate (Maximum)	150	Continuous	Monthly
Injection Rate (Average)	50	Continuous	Monthly
Cumulative Estimated Annual Volume	26,280,000 gallons/year	Continuous	Monthly
Injection Pressure (maximum)	944 psig	Continuous	Monthly
Injection Pressure (average)	500 psig	Continuous	Monthly
Annulus Pressure	100 psig min.	Continuous	Monthly
Annulus/Tubing Pressure Differential	100 psig min.	Continuous	Monthly
Sight Glass Level	Visible	Daily, when operated	Monthly
Annulus Fluid Addition Or Removal	None	Monthly	Monthly
Chemical Composition of Injected Fluids[1]	None	Monthly	Monthly
Physical Characteristics of Injected Fluids[1]	Non-hazardous	Monthly	Monthly

[1] As specified in the Waste Analysis Plan, see Attachment C (CD-ROM)
[2] Continuous is to be defined as a value recorded not less than once every five (5) minutes

Impact of Injection

There is one well that penetrates the confining zone into the uppermost injection zone within the two-mile AOR. The nearest wells that penetrate the injection zone and injection interval are the two Class I non-hazardous wells at the Consumers Energy Generating Station in Zeeland, MI, located approximately 4.5 miles to the northwest of the proposed IW-1 well.

The Mt. Simon will be tested to verify capacity upon well installation. Until data are obtained during installation of the well, conservative estimates of formation properties have been assigned based on regional data associated with the closest well to the Mt. Simon being the Consumers Energy wells in Zeeland (Permit Nos. MI-139-1I-004 and 005), and projected operational parameters, to generate an estimate of the fluid front for the IW-1 well. Standard equations for the volume of a porous cylinder can be used with the following parameters to generate an estimate for a simplistic piston-like displacement fluid front radius. Based on parameters determined at Consumers Energy Well No. 1, the following conservative formation characteristics and injectate volumes were assumed:

- 350 foot net Mt. Simon thickness, conservatively assumed from >900 ft total thickness of this formation
- 1,577,880,000 gallons of injectate estimated based on twenty years of continuous injection at a rate of 78,894,000 gallons per year (150 gpm)

The following formula was used to estimate plume dimensions:

$$\text{Radius} = (\text{volume} / \pi * \Phi * h)^{1/2}$$
$$= [(1{,}577{,}880{,}000 \text{ gal} * \text{ft}^3/7.48 \text{ gal}) / \pi * 0.1 * 350]^{1/2}$$
$$= 1{,}385 \text{ ft}$$

As an estimate for illustrative purposes, this calculation yields a piston-like, 100 percent injected fluid front radial distance of approximately 1,385 feet from the well. Although dispersion will play a role in spreading this plume over a slightly larger area, even a relatively large dispersivity combined with a low cut-off boundary concentration would likely yield a plume that reaches a radial distance of just over ¼-mile from the well. This is much smaller than the two-mile mile AOR radius for which artificial penetrations were identified and evaluated. As previously noted, there are no wells located within the AOR that penetrate the injection or confining zones. Additional evaluation of dispersion, diffusion and/or displacement of injected fluids and behavior of transient pressure gradients in the injection zone during and following injection will be conducted upon site-specific information becoming available from testing the well.

Compatibility problems encountered due to injection of non-hazardous landfill leachate and gas condensate are possible due to injection of particulate matter that could cause decreased flow capacity. Screens or filters may be used to condition fluids if needed.

Due to the composition of the fluid to be injected and landfill origin, periodic biocide treatments may be instituted as needed to prevent the establishment of bacterial plugging issues. Also, it is possible that the concentration of iron within injectate could lead to precipitation issues within tubing, pipe, or the formation, so implementation of a system to prevent plugging or treat iron may be required. Such solids, compatibility, or bacterial problems, if they do occur, would not be a containment issue, but would be an operations issue. If plugging occurred and was not remedied, the operator could reduce injection rates so that maximum pressure limits are not exceeded. To sustain rates if such a situation develops, periodic stimulations may be required, but would be accomplished within regulatory requirements. At this time, only relatively low suspended solids fluids from the Autumn Hills RDF will be injected in the well.

B.13 Proposed operating data including all of the following data:
A. The anticipated daily injection rates and pressures.
B. The types of fluids to be injected.
C. A plan for conducting mechanical integrity tests.

A and B. As noted in Section B.12, continuous injection at an average rate of 50 gpm (72,000 gallons per day) is projected. This is equivalent to an injection volume of not more than approximately 26,280,000 gallons per year. At the maxiumum permitted injection rate of 150 gpm, injection volume is equivalent to not more than approximately 78,840,000 gallons per year. As noted on Table B.12-2, average injection pressure is estimated to be approximately 500 to 800 psig with a maximum injection pressure of not more than 944' psig. The injectate will be non-hazardous fluids generated on-site from landfill leachate and gas condensate collection systems. As necessary, storm water, surface water run-off, and/or fluids derived from or necessary for well IW-1 operation and maintenance may also be injected. See Item B.9 and B.12 for additional information pertaining to daily injection rates/pressure and the types of fluids to be injected.

C. Annual Part I mechanical integrity testing for IW-1 will include reservoir monitoring as specified by permit requirements in addition to static annulus pressure testing. WM will provide the agency a minimum of 30 days notice prior to annual testing. Although test procedures or methods may be changed based on approval by MDEQ staff, the following procedure will be used for the first such testing performed:

1. Conduct Wellsite Safety Meeting
    a. Prior to commencement of field activities, conduct safety meeting with contractors and personnel to be involved with field services and MIT testing. Ensure that all safety procedures are understood and review days' work activities.
2. Conduct Reservoir (Fall-Off or Static) Pressure Test
    a. For fall-off, record data regarding test well injection at typical operating conditions (constant rate). Rate versus time data will be recorded during the injection period. Cumulative injection volume will also be recorded. Continue injection for a minimum of approximately 8 hours. Note that significant rate variations may yield poor quality data or require more complicated analysis techniques.
    b. Rig-up pressure gauge and run in well to a depth likely not to exceed approximately 5,600 feet or other depth approved by MDEQ.
    c. For pressure transient fall-off, obtain final stabilized injection pressure for a minimum of 1 hour. For static test, collect a minimum of two pressure/temperature readings at depth. Ensure that the gauge temperature readings have also stabilized.
    d. After gauge recordings are stable, cease injection and monitor pressure fall-off. Continue monitoring pressure for a minimum of 8 hours or until a valid observation of fall-off curve is observed. For a static gradient survey, the well will be shut-in for a minimum of 48 hours before testing. Wellbore

pressure gradients will be obtained to establish fluid gradient and bottomhole pressure data will be collected for a minimum of 4 hours for static testing.

   e. Stop test data acquisition, rig-down and release equipment.

3. Annulus Pressure Test
   a. Stabilize well pressure and temperature.
   b. As practical, arrangements will be made for a representative from the MDEQ to be present to witness testing.
   c. Install ball valve or similar type “bleed” valve on annulus gate valve. Pressurize annulus to a minimum of 100 psig above maximum permitted operating pressure and shut-in valve. Install certified gauge on “bleed” type valve. The annulus may need to be pressurized and bled off several times to ensure an absence of air.
   d. Monitor and record pressure for 1 hour. Pressure may not fluctuate more than 3% during the one-hour test.
   e. Lower the annulus pressure to normal operating pressure at the end of the test.

Part II mechanical integrity testing to be conducted every 5 years, as required by MDEQ, is detailed in Sections A.11 and A.14 and is not repeated herein.

B.14 For a proposed disposal well to dispose of waste products into a zone that would likely constitute a producing oil or gas pool or natural brine pool, a list of all offset operators and certification that the person making application for a well has notified all offset operators of the person's intention by certified mail. If within 21 days after the mailing date an offset operator files a substantive objection with the supervisor, then the application shall not be granted without a hearing pursuant to part 12 of these rules. A hearing may also be scheduled by the supervisor to determine the need or desirability of granting permission for the proposed well.

Production from the Mt. Simon interval has not been identified in the vicinity of the proposed disposal well. There are also no deep wells within the vicinity of the Autumn Hills RDF that penetrate to or produce from zones below Prairie du Chien Group, which is the proposed upper confining zone. Therefore, a list of offset operators is not required.

B.15 A proposed plugging and abandonment plan

The following is the proposed plan for plugging and abandonment of the proposed IW-1 well:

AUTUMNS HILLS IW-1 PLUGGING AND ABANDONMENT PLAN

1. Notify regulatory agencies a minimum of 30 days prior to commencement of plugging operations.
2. Prepare well and location for plugging. Move in and rig up well servicing rig, pipe racks and tanks.
3. Install a test gauge on the annulus to perform a static annulus pressure test. Ensure that the annulus is fluid filled and that the well has been shut-in for a minimum of 24 hours. Pressurize annulus and isolate from the annulus system. Monitor annular pressure for one hour.
4. Displace tubing with kill brine as needed to control wellhead pressure. Dismantle wellhead and install blow-out preventer. Displace annulus with kill brine as needed to control pressure. Brine compatibility with cement to be used will be verified.
5. Remove injection tubing and packer. If packer will not unseat, proceed with fishing operations as needed to remove packer from hole or obtain approval to set retainer above packer and pump cement through retainer and abandoned packer.
6. Make up mechanical retainer on workstring and trip in hole. Set cement retainer at top of injection interval just above historical packer setting depth. Test cement retainer to 500 psig.
7. Move in cement and cementing equipment.
8. Displace hole below retainer with Class "A" cement. Unsting from retainer and spot 50 additional sacks (sx) on top of retainer. Cement volume has been calculated based on the following volumes:
   - 6-1/8" hole from 5,600 ft GL to a maximum of 6,600 ft GL, at 0.2046 ft^3/ft = 205 ft^3, or 174 sx Class "A" cement
   - 7" casing from surface to 5,600 ft GL, at 0.2148 ft^3/ft = 1,203 ft^3, or 1019 sx Class "A" cement

   Therefore the total volume of the plugs is estimated to be 1,408 ft^3, which is equivalent to 1,193 sx of Class "A" cement with a yield of 1.18 ft^3/sack. If wellbore fill is present, this volume may have to be reduced or squeezed into the openhole of the injection interval.
9. Once cement has been tagged on top of the retainer, spot successive, continuous balanced cement plugs in 500' intervals from top of cement retainer to surface (6 intervals required). Cement to be API Class 'A' with not more than 4% bentonite. If neat Class 'A' cement is pumped it will have the following slurry properties.
   - Water ratio – 5.2 gallons per sack
   - Slurry weight – 15.60 pounds per gallon

- Slurry volume – 1.18 ft^3/sack

An estimated 969 sacks, or 1,143 cubic feet, of slurry will be required above retainer.

10. Remove BOP and wellhead equipment
11. Cut off wellhead approximately 4 feet BGS and weld cap with permanent marker on casing.
12. Rig down and move out all equipment.
13. Prepare and file USEPA and MDEQ Plugging Reports.

The steel plate will be inscribed with the disposal well identification information and the date of plugging. Federal and State representatives will have been invited to witness the plugging and sign the plug and abandonment form.

B.16 Identify the source or sources of proposed injected fluids. Identify if injected fluids will be considered hazardous or non-hazardous as defined by Part 111, Hazardous Waste Management, of the Natural Resources and Environmental Protection Act, 1994 PA 451, as amended (NREPA)

See Section B.9 for information about waste sources and waste chemistry. As stated in Section B.9, non-hazardous landfill leachate and gas condensate will be injected in the proposed IW-1 well. Injection of fluids generated on-site will provide an environmentally safe management option that does not require off-site transport with associated traffic, potential for fluid spillage, and other issues. Waste Management of Michigan, Inc., believes Class I authorization will provide the most environmentally safe option for management of on-site generated fluids into formations deeply isolated from overlying USDWs. This will safely, cost effectively, and efficiently manage non-hazardous fluids via injection while minimizing the risks associated with transporting such wastes substantial distances to utilize other fluid management methods.

B.17 Whether the well is to be a multisource commercial hazardous waste disposal well.

This well permit application request is for a single source non-hazardous well, not a multisource commercial hazardous waste disposal well.

B.18 Additional information required for an application for a permit to drill and operate a storage well or to convert a previously drilled well to such a well:

For an application to drill storage well or to convert a previously drilled well to a storage well, also submit the following information in addition to that submitted in the previous section for a disposal well. In the previous sections instructions, replace the term 'disposal' with 'storage' and 'waste' with 'stored product.'

1. **The name and chemical formula of the product to be stored, and a characterization of the physical, chemical, and hazardous or toxic properties of the product.**
2. **The anticipated vertical and horizontal dimensions and volume of the completed underground storage cavity.**
3. **The anticipated operating life of the underground storage cavity.**
4. **The method to be used to create the underground storage cavity.**
5. **The name of the geological stratum in which the underground storage cavity will be created.**
6. **A schematic diagram of the well bore showing the proposed arrangement and specifications of the down hole well equipment.**
7. **If the underground storage cavity is to be formed by solution mining bedded salt, then all of the following information shall be included:**
8. **The plan for disposal of brine produced during solution mining of the underground storage cavity and for the operating life of the underground storage cavity.**
9. **The expected starting and ending dates of the solution mining.**
10. **The range of anticipated operating pressures of the underground storage cavity.**
11. **The anticipated range of operating injection pressure.**
12. **The proposed method of displacing stored product.**
13. **A plan for testing the mechanical integrity of the underground storage cavity as provided in R 299.2392 and R 299.2393.**

N/A. This application is not being submitted for a permit to drill and operate a storage well or to convert a previously drilled well to such a well.

B.19 Additional information required for an application for a permit to drill and operate a well for the production of artificial brine or to convert a previously drilled well to such a well:

For an application to drill and operate a brine well for production of artificial brine or to convert a previously drilled well to a well for production of artificial brine, submit in addition to the information in the first section, all of the following proposed information:

1. **If the well will be drilled into an existing cavern, the number of wells in the cavern, the present extent of the cavern, and the purpose of the proposed well.**
2. **The name of the geological stratum or strata to be mined, the top and bottom depths of the mined zone, the gross and net mineable thickness, and the mineral or minerals to be recovered by solution mining.**
3. **An isopach map showing thickness and areal extent of the strata to be mined.**
4. **A sketch showing the extent of the planned mine area.**
5. **The geological strata to be left in place for roof support.**
6. **A diagram showing the well bore with the proposed casing program and its relationship to the stratum or strata to be mined.**
7. **A plan for conducting subsidence monitoring as required in R 299.2407 or a rationale for not conducting subsidence monitoring.**

N/A. This application is not being submitted for a permit to drill and operate a well for the production of artificial brine or to convert a previously drilled well to such a well.

A public hearing may be scheduled by the Supervisor of Mineral Wells to take public comment on the proposed well. If such a hearing is scheduled, the applicant will be responsible for the scheduling and preparation and publication of the notice.

Please collate the above documents into a set and mail the original and two copies of the application (total of 3 sets) plus 3 additional copies of form EQP 7200-1 to:

Department of Environmental Quality
Office of Geological Survey
P.O. Box 30256
Lansing, Michigan 48909

The above documents have been collated and appropriate numbers of document and form copies have been sent to the above address.