Model Inputs

ComEd uses Integral Analytics' DSMore software to conduct its cost-effectiveness testing. This software, which is an add-on to Microsoft Excel, uses a variety of data inputs to perform multiple analyses. The following data is used:

Avoided energy cost: In January 2013, ComEd provided a three-year price strip of hourly energy supply costs to Integral Analytics (IA). This forecast was developed by Northbridge, and uses energy future prices for the Northern Illinois Hub. Since these futures prices are only for monthly fixed block, on-peak or off-peak times, the prices are "shaped" by applying historical hourly price profiles to them; the resulting price profile more appropriately represents the expected hourly variations that occur in the day-ahead and real-time markets. ComEd provides this data, along with at least one year of hourly load data for each of ten customer classes, to IA. IA takes this data, along with 33 years of historic weather data for the Chicago-O'Hare weather station and develops class-based GARCH models, which become the basis for avoided energy cost calculations in the DSMore software.

This profile development is completed every three years. Annually, on or around June 1 of each year, ComEd re-calibrates the cost model by obtaining new future prices from NYMEX for the Northern Illinois Hub and calculating an ATC cost. Page 4 shows the derivation of the current ATC price.

Carbon adder: The Illinois TRC test requires ComEd to include "reasonable estimates … of financial costs likely to be imposed by future regulations and legislation on emissions of greenhouse gases." (20 ILCS 3855/1-10). For 2016, the Energy Information Administration ("EIA") evaluated the impacts of carbon regulation attributed to the EPA's Clean Power Plan ("CPP") on future energy prices as part of its Annual Energy Outlook ("AEO") Reference Case; this approach reflects the effect that the CPP would have on power plant construction, retirements and dispatch over time. ComEd believes the AEO Reference case represents a reasonable estimate of the impacts of emissions regulations on the cost of energy. The impacts of the CPP is included in the escalator values as described below.

Avoided capacity cost: ComEd is a member of PJM Interconnect, and its costs for capacity are based on the Reliability Pricing Model (RPM); that is, PJM's forward capacity market. ComEd exists in the ComEd zone within PJM market; this submarket was established by PJM for the first time in 2014, which means that there are potentially binding transmission constraints that would limit PJM's ability to import power into the ComEd zone from other zones; such constraints tend to increase the cost of capacity within the constrained zone.

In June 2015, FERC approved PJM's Capacity Performance ("CP") modifications to the capacity market. Where capacity had previously been valued on summer-only availability, CP is valued on year-round availability. Summer-only, or Base, capacity will be phased out from the capacity market by June, 2020. ComEd has calculated an average capacity value based on the percentage of energy efficiency capacity that qualifies as CP in the Base Residual Auctions and Transitional Auctions that took place during 2015 and 2016.

Avoided Transmission and Distribution Costs: ComEd conducted an updated analysis to place a value on the avoidance or deferral of new transmission and distribution capacity as a result of energy efficiency. The most recent analysis determined that an avoided T&D cost of $33.32/yr is appropriate for cost-effectiveness analysis.

Escalation Factors: All of the above values are determined either for one or three years, based on the time horizon for which market data is available. Since most energy efficiency measures have lives that will exceed this limited time horizon, ComEd relies on price forecasts from EIA to derive escalation factors over the remainder of the 25-year time horizon that DSMore uses. These factors are taken from the 2016 AEO report for the East North Central region of the country, and reflect the average retail price forecast for all customers. For 2016, the EIA's Reference Case (the primary forecast that is used for policy-making) assumes that the CPP will become effective per the timeline established in the EPA's final rule, and it further assumes that a mass-based approach to compliance, using regional trading markets, will be used by most states for compliance. Pages 5-6 show the derivation of the current energy and capacity escalators.

Since the AEO values are provided in constant dollars, ComEd applies an inflation adjustment to these factors. This adjustment is derived annually by using the real and nominal 20-year yields from the U.S. Treasury web site.

Distribution losses: Since all avoided costs are based on "busbar" energy and capacity, DSMore uses distribution loss factors to take the measure savings and convert them to busbar values. In the past, ComEd relied exclusively on its Distribution Loss studies which are prepared in support of rate cases. These studies determine the average annual losses as a percentage of load, as well as the peak loss value. Based on guidance from NRDC, ComEd has conducted some empirical analyses to assess the marginal losses associated with energy efficiency. This type of analysis is rooted in the expectations that, since a significant fraction of distribution losses are non-linear (I2R losses), reducing the load on a given feeder, transformer or substation will reduce distribution losses for the remaining load. ComEd's Capacity Planning department conducted a few scenario analyses using CYME power calculation software from

Cooper Technologies. CYME can provide an 8,760 hour analysis using actual feeder data that has been collected through SCADA. These scenarios were limited to three individual feeders due to the complexity involved in modeling systems through CYME. The results of these analyses showed marginal/average loss ratios ranging from 0.9 to 2.1, with an averaged value around 1.65. This value was extrapolated to the remaining distribution system to arrive at a new value of 9.24% marginal distribution loss.

Unlike distribution losses, transmission losses are based solely on the average loss factors; this is due to the way the transmission system is managed by PJM – there is a substantial amount of non-native load on this system; as a result we see transmission peaks that do not coincide with distribution peak loads. This is likely due to available transmission capacity being recaptured to route power into and out of the ComEd zone of PJM. In other words, any reduction in transmission load due to energy efficiency would likely be repurposed for other revenue-generating power movement. While inclusion of average losses is needed to convert customer savings to busbar avoided costs, marginal losses at the transmission level would likely lead to an overstatement of avoided costs. We used the average loss factor of 1.78% for transmission losses.

The combined T&D loss factor is 9.24% plus 1.78%, or 11.02%.

Peak T&D loss ratio:

The 2011 Distribution loss study identified a peak T&D loss value of 14.46%, and an average loss value of 7.38%. The ratio of these two factors is 1.96, which represents the peak T&D loss ratio to be used by DSMore. We assume that this ratio contribution is equally applicable to marginal losses. Since DSMore does not allow direct entry of a peak T&D loss factor for avoided capacity cost purposes, ComEd treats the 1.96 ratio as a multiplier against the avoided capacity cost in its model.

Around-The-Clock (ATC) Electric Supply Cost

	UM	UO	ATC Price Calculator						
			Days in Month			Hours in Month			
	Peak	Off-Peak	Peak	Off-Peak	Total	Peak	Off-Peak		
6/1/2016	$ 34.58	$ 21.98	22	8	30	352	368	720	$ 28.14
7/1/2016	$ 45.98	$ 21.98	21	10	31	336	408	744	$ 32.82
8/1/2016	$ 43.74	$ 21.98	23	8	31	368	376	744	$ 32.74
9/1/2016	$ 35.34	$ 19.15	22	8	30	352	368	720	$ 27.07
10/1/2016	$ 33.50	$ 19.88	21	10	31	336	408	744	$ 26.03
11/1/2016	$ 34.88	$ 21.10	22	8	30	352	368	720	$ 27.84
12/1/2016	$ 39.50	$ 24.04	22	9	31	352	392	744	$ 31.35
1/1/2017	$ 55.67	$ 32.52	22	9	31	352	392	744	$ 43.47
2/1/2017	$ 52.95	$ 29.23	20	8	28	320	352	672	$ 40.53
3/1/2017	$ 40.16	$ 25.71	23	8	31	368	376	744	$ 32.86
4/1/2017	$ 35.84	$ 22.64	20	10	30	320	400	720	$ 28.51
5/1/2017	$ 36.33	$ 19.18	23	8	31	368	376	744	$ 27.66
6/1/2017			*261*	*104*	*365*	*4,176*	*4,584*	*8,760*	**$ 31.58**

This workbook will calculate an unweighted ATC price for the Northern Illinois Hub of PJM

This sheet calculates the Around-The-Clock (ATC) electric supply price to be used by DSMore. Data is retrieved from the CMEGRoup website for the Northern Illinois Hub prices. Product UM provides monthly on-peak prices, while product UO provides off-peak prices.
1) Enter the starting date of the 12-month period under consideration in Cell C8.
2) For each product, enter the monthly per-MWh value in the corresponding cells for UM and UO.
3) The annual ATC price should display in Cell N20; this value will automatically populate into the "Electric Supply Escalators" tab as well.
4) verify that the total annual hours in cell L20 total 8,760 (8,784 if the 12 months under consideration include a "leap month").

General Inflation Rate

20-year Treasury Yield	2.22%
20-year Treasury Real Yield	0.74%
Inflation Rate	1.47%

The inflation rate is estimated by comparing the annual yield curve value for 20-year Treasury Notes with the associated Daily Real Yield value for the same series. These values are taken for the month of June each year. The resulting inflation rate is applied to the various escalator curves to provide nominal escalators.

*AEO costs cents per kWh (generation only)

	A	B	C
	AEO 2016 CPP	AEO 2016 base 2017	Inflation-adjusted
2013			
2014	5.09		
2015	5.87		
2016	5.87		
2017	5.78	1	1.028
2018	5.81	1.005	1.049
2019	5.81	1.006	1.065
2020	5.72	0.989	1.063
2021	5.63	0.974	1.062
2022	6.21	1.075	1.189
2023	6.70	1.160	1.301
2024	6.83	1.182	1.346
2025	6.87	1.188	1.373
2026	6.92	1.198	1.404
2027	7.08	1.226	1.458
2028	7.28	1.260	1.521
2029	7.58	1.312	1.607
2030	7.79	1.348	1.675
2031	7.59	1.314	1.657
2032	7.37	1.276	1.632
2033	7.29	1.262	1.639
2034	7.20	1.246	1.642
2035	7.13	1.233	1.648
2036	7.09	1.227	1.665
2037	7.05	1.220	1.679
2038	7.03	1.216	1.698
2039	6.97	1.205	1.708
2040	6.85	1.184	1.703
2041	6.59	1.141	1.664

For 2016, the EIA established a Reference case using Clean Power Plan compliance via multi-state mass-based markets (allowances). Also, NYMEX energy price futures are no longer provided for a full three years via CME's portal. These changes necessitate a change in approach for developing forward energy price curves in DSMore.

1) the 2016 (Year 1) ATC price will continue to be derived from NYMEX futures, consistent with guidance from Integral Analytics.
2) the first year escalator will be used to calibrate the ATC price with the chosen electric price scenario within DSMore.
3) all years from 2017 onward will use AEO price forecasts from Table 3 of the AEO datasets. Average price paid by all customers for electricity in the East North Central region will continue to be used (Column A).
3a) For 2016, ComEd is using Generation cost per kWh, excluding transmission and distribution costs.
Column B "normalizes" the AEO prices against the first year value to create annual price ratios.
6) Column C calibrates the entire Column B trajectory to reflect the Step 2 adjustment, and it incorporates inflation.

Electric Capacity Escalators

Marginal Peak Multiplier	1.96					
Inflation Rate	1.47%					

	CP	Base	CP %	Weighted Avg Cost	FPR	DR	ICAP Cost
2016 RPM	$ 134.00	$ 59.37	75%	$ 115.57	1.0902	0.955	$ 120.32
2017 RPM	$ 151.50	$ 120.00	75%	$ 143.72	1.0916	0.953	$ 149.51
2018 RPM	$ 215.00	$ 200.21	73%	$ 210.93	1.0835	1.000	$ 228.55
2019 RPM	$ 202.77	$ 182.77	73%	$ 197.27	1.0881	1.000	$ 214.65
2018-19 Avg	$ 208.89	$ 191.49					$ 221.60

	A	B	C
	AEO 2016 CPP	AEO 2016 base 2020	Inflation-Adjusted
2013	0		
2014	5.09		
2015	5.87		
2016	5.87		
2017	5.78		1.000
2018	5.81		1.529
2019	5.81	1.006	1.436
2020	5.72	0.989	1.482
2021	5.63	0.985	1.496
2022	6.21	1.086	1.676
2023	6.70	1.172	1.834
2024	6.83	1.195	1.898
2025	6.87	1.201	1.935
2026	6.92	1.210	1.979
2027	7.08	1.239	2.055
2028	7.28	1.273	2.143
2029	7.58	1.326	2.265
2030	7.79	1.362	2.360
2031	7.59	1.328	2.335
2032	7.37	1.289	2.300
2033	7.29	1.276	2.310
2034	7.20	1.259	2.314
2035	7.13	1.246	2.323
2036	7.09	1.240	2.346
2037	7.05	1.233	2.367
2038	7.03	1.229	2.393
2039	6.97	1.218	2.407
2040	6.85	1.197	2.400
2041	6.59	1.153	2.345

1) Capacity prices for 2016-2019 are taken from PJM Base and transition auction results, and reflect CP and Base clearing prices for the ComEd zone.

2) 2020 Capacity value uses average of 2018 and 2019 CP clearing price, as these were only two years to have CP in the Base Residual Auction and it is believed that these reflect the expected value for the 2020 auction. 2016 and 2017 CP prices are based on special transitional auctions that followed different rules than base auctions.

3) all years from 2021 onward will escalate prices using the same methodology that is used to determine electric supply escalators.

3) Column C calibrates the entire Column B trajectory against the final known RPM auction result, and it incorporates inflation.

Capacity Cost

2016 RPM Cost	$ 149.51	/MW-day (weighted average of CP and Base)
Forecast Pool Requirement	1	
Demand Resource Factor	1	
2011 Average Distribution Loss	5.60%	
2011 Peak Distribution Loss	14.46%	
Average Transmission Loss	1.78%	
Marginal/Average Loss Ratio	1.65	
eak/Average Distribution Ratio	2.6	
Marginal energy Loss	11.02%	
marginal peak loss	25.6%	

Annual Capacity Value

Before Loss Adjustment	$ 54.57	/kW-year
After Loss Adjustment	$ 68.56	/kW-year