BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of the Ohio	**)**	
Edison Company, the Cleveland Electric	**)**	
Illuminating Company and the Toledo Edison	**)**	**Case No. 14-1297-EL-SSO**
Company for Authority to Provide for a Standard	**)**	
Service Offer Pursuant to R.C. 4928.143	**)**	
In the Form of an Electric Security Plan	**)**	

Third Supplemental Testimony of Tyler Comings

Redacted Version

On Behalf of
Sierra Club

December 30, 2015

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I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q Please state your name, business address, and position.

A My name is Tyler Comings. I am a Senior Associate with Synapse Energy Economics, Inc. (Synapse), which is located at 485 Massachusetts Avenue, Suite 2, Cambridge, Massachusetts.

Q Are you the same Tyler Comings who filed direct testimony in this matter on December 22, 2014, supplemental testimony on May 11, 2015, and second supplemental testimony on October 13, 2015?

A Yes.

Q What is the purpose of your third supplemental testimony?

A My third supplemental testimony addresses the Third Supplemental Stipulation and Recommendation, which was filed on December 1, 2015. My testimony focuses on the proposed transaction in the Rider RRS. I discuss the reasonableness and currentness of the assumptions and forecasts being used by the Companies to project the potential cost or benefit to customers of the revised proposal.

Q Are there any exhibits that accompany your testimony?

A Yes. I am attaching Exhibits TFC-43 to TFC-45.

II. SUMMARY OF TESTIMONY

Q Please summarize your third supplemental testimony.

A My testimony shows the following key points:

1. In the first 31 months of the transaction, the Companies project a net loss of $364 million to ratepayers while using FES's forecasts leads to a projected [redacted] over that same time period.

2. While the Companies project a total benefit to customers of $260 million over the eight years of the proposed transaction, that projection is based on outdated and unreasonable forecasts of energy, natural gas, and capacity prices.

3. Using FES's assumptions shows that ratepayers [redacted] projected for the first 31 months and, [redacted], would experience a [redacted] over the eight year term. (see COMPETITIVELY SENSITIVE CONFIDENTIAL Figure 1). This is not surprising given that if FES (a profit-maximizing entity) believed the plants to be [redacted], then it would not offer this transaction in the first place.

4. The Companies' valuation relies on natural gas prices that are [redacted] and outdated. Natural gas prices have averaged $2.69 per MMBtu in 2015. Yet the ICF natural gas forecast used by the Companies in this proceeding predicted a price of $4.34 per MMBtu in 2015, which is an overestimate of 61% (see CONFIDENTIAL Figure 2). ICF has developed a much [redacted] natural gas price forecast more recently but the Companies have not incorporated that or any other up-to-date natural gas price forecast in this case. The inclusion of such a forecast would make the coal generation involved in the proposed transaction [redacted] competitive.

5. The Companies' valuation relies on energy prices that are [redacted] and outdated. The Companies have relied on ICF projections that [redacted] ATSI and AEP-Dayton Hub 2015 energy prices by [redacted] (see CONFIDENTIAL Table 3). Use of [redacted] energy prices has led the Companies to [redacted] both the capacity factor and potential energy revenue from the Sammis plant.[1] In contrast to the Companies'

[1] Net plant generation from EIA's Electricity Data Browser, Plant level data report (available at:

assumptions, FES assumed [redacted] energy prices through 2020, which lead it to value the transaction much [redacted] and conclude that ratepayers would [redacted] over the eight year term of the proposed transaction.

6. The Companies' valuation relies on capacity prices that are [redacted] and outdated. The Companies [redacted] the 2018/2019 capacity price (see CONFIDENTIAL Figure 4). In addition, PJM has lowered its load forecast in 2015, and is proposing to do so again in 2016 (see Figure 5), while the Companies continue to rely on a load forecast from 2014 in this case. Further reductions in load forecasts put further downward pressure on capacity prices that have not been accounted for in the Companies' valuation.

II. [redacted] THE COMPANIES [redacted] SHOW THAT RATEPAYERS WOULD PAY HUNDREDS OF MILLIONS IN THE FIRST 31 MONTHS OF THE PROPOSED TRANSACTION

Q Has the Third Supplemental Stipulation and Settlement changed the terms of the proposed transaction?

A Yes, in two ways. First, the length of the proposed transaction has been shortened from 15 years to eight years. Second, the return on equity that the Companies would pay to FES has been reduced from 11.15% to 10.38%.[2]

Q What will the proposed transaction cost ratepayers in the first 31 months?

A Under the Companies' analysis of the settlement proposal, the proposed transaction results in a $364 million loss for ratepayers from June 1, 2016 through December 31, 2018 (31 months). COMPETITIVELY SENSITIVE CONFIDENTIAL Figure 1 shows the cumulative net present value of the

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http://www.eia.gov/electricity/data/browser/.) Companies' projection is from workpapers of Jason Lisowski.

[2] Fifth Supplemental Testimony of Eileen M. Mikkelsen, p.7, lines 1-10.

proposed transaction for the shortened term (June 2016 through May 2024) and with the lower return on equity.[3]

[redacted]

COMPETITIVELY SENSITIVE CONFIDENTIAL Figure 1: Valuation of the Proposed Transaction by the Companies and FES (Cumulative NPV, $2015 mil)[4]

Q Are significant future gains necessary to make the proposed transaction a net benefit to ratepayers over the eight-year term?

A Yes. The Companies' analysis shows a net loss of $364 million in the first 31 months of the proposed transaction. The Companies project net gains from 2019 through the end of the term. (In COMPETITIVELY SENSITIVE CONFIDENTIAL Figure 1 above, this is shown by the cumulative net benefit increasing after 2018). These net gains are needed in order to make up for the losses incurred in the first three years. The "breakeven" point occurs when the value of the net benefit becomes positive, which is 2021 in the Companies'

[3] Data Response OCC Set 17-RPD-10-Attachment 1. Summation of "NPV Under/(Over) Recovery" for $144.5 million in 2016, $151.6 million 2017, and $67.4 million in 2018.
[4] Data Response OCC Set 17-RPD-10-Attachment 1. Attachments FES-1 through 4.

analysis. (In COMPETITIVELY SENSITIVE CONFIDENTIAL Figure 1 above, this is shown by the cumulative net benefit crossing the x-axis by 2021).

Q How do the Companies justify these projected future gains starting in 2019?

A The Companies are relying on forecasts of natural gas, energy, and capacity prices that are favorable to the transaction to support their assertion that customers will realize a net gain sometime in the future. However, we now know that these outdated forecasts are [redacted], as I will discuss further in the next section.

Q Is it likely that the Companies [redacted] losses in the early years?

A Yes, for the same reasons that their projected gains in the later years are likely [redacted]. In 2015, actual natural gas, energy, and capacity prices have all turned out [redacted] than what the Companies had projected and that they continue to rely on in this filing. As it was for 2015, their outlook for 2016 through 2018 is outdated and [redacted] biased—meaning the predicted losses in these early years are likely [redacted].

Q Did FES find that the proposed transaction would cost ratepayers more in the early years?

A [redacted] As I discussed in my direct testimony, the Companies substituted their own assumptions (generated by ICF) in place of FES's assumptions—the latter of which used [redacted] energy prices and [redacted] carbon prices.[5] As shown in COMPETITIVELY SENSITIVE CONFIDENTIAL Figure 1, under FES's assumptions, the proposed transaction would result in a net [redacted] to ratepayers from June 2016 through the end of 2018.[6]

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[5] Direct Testimony of Tyler Comings, p.8, lines 8-17.

[6] Attachment FES-4 adjusted with new ROE (10.38%). Undiscounted [redacted] are [redacted] in 2016, [redacted] in 2017, and [redacted] in 2018. The net present value (i.e. discounted) value of these [redacted] is [redacted].

Q Did FES project that there would be [redacted] in the future to make up for [redacted] through 2018?

A No. Under FES's assumptions, the proposed transaction would [redacted] during the eight year term. As shown in COMPETITIVELY SENSITIVE CONFIDENTIAL Figure 1, using FES's assumptions with the new ROE of 10.38% leads to a [redacted] through the end of the term.

Q As a [redacted], would FES offer this deal if it thought the plants would become [redacted] on their own?

A No. FES's analysis of the transaction shows that it expects [redacted] through 2024. Under the proposal, FES will be made whole and get a guaranteed rate of return at the expense of ratepayers. If FES expected the plants to be [redacted] on their own over the eight-year period, then—[redacted]—it would not offer the deal to ratepayers.

Q Would the new "[redacted]" in the proposed stipulation be triggered under either the Companies or FES valuation estimates?

A No. The Companies claim that the settlement includes "[redacted]" as a "[redacted]."[7] These "credits" would be paid by the Companies, not FES. Therefore, FES and its shareholders—as owners of the plants--are not [redacted] with ratepayers. Moreover, this "[redacted]" mechanism is only triggered if there are losses or insufficient gains in each year—starting in 2020. In the first three years—when [redacted] the Companies [redacted] agree there will be significant losses to ratepayers—there is no possibility of a credit. Starting in 2020, [redacted] predict annual gains such that the credit would not be triggered.

[7] Fifth Supplemental Testimony of Eileen M. Mikkelsen, p.3, line 25 through p. 4, line 3.

Q Given the substantial upfront losses that ratepayers will incur, should the proposed transaction be pursued?

A No. The proposed transaction is valued based on information and assumptions that are outdated and unfairly biases the transaction to look favorable. Further, the transaction transfers significant market risks from FES to the Companies' customers. If the underlying plants were [redacted] on their own then FES would not need to offer this transaction.

Through 2018, the transaction is expected to cost $364 million (according to the Companies) in net present value—$155 million of which is in the first seven months alone. FES expects [redacted] through 2018 and that the proposed transaction [redacted] over the eight year term. Therefore, FES is offering virtually certain [redacted] for ratepayers in exchange for [redacted]. These substantial projected short-term [redacted] and long-term risks to ratepayers demonstrate that the proposed transaction should not be pursued. No parties argue over the fact that ratepayers will [redacted] as soon as this deal is in place. The question is: how long will ratepayers continue to [redacted]?

III. <u>THE TRANSACTION IS MORE COSTLY FOR RATEPAYERS THAN IT APPEARS BECAUSE THE COMPANIES HAVE NOT UPDATED KEY INFORMATION</u>

Q Have the Companies updated their assumptions of the value of the proposed transaction?

A Only somewhat. The Companies have estimated the net present value of the transaction with the lower ROE and shorter term. However, the value of the transaction is highly dependent on natural gas, energy, and capacity prices that the Companies have not updated from the original analysis filed in August 4, 2014—

using load forecasts produced in February 2014 and natural gas price forecasts produced in [redacted].[8]

Q Would updating this information change the value of the proposed transaction?

A Yes. As I have described previously, the proposed transaction turns ratepayers into "de-facto merchant generators" that would be vulnerable to market risks.[9] The transaction would only provide a benefit to ratepayers if market prices generate enough revenue to more than make up for the cost of operating the plants and the rate of return that the Companies are obligated to pay to FES.

As I describe below, since the original filing, forecasts of natural gas prices, energy prices, and capacity prices have all turned out to be [redacted] than the Companies originally anticipated. By continuing to rely on outdated market price projections, the Companies are overstating the projected value of the eight year proposed transaction set forth in the Third Supplemental Stipulation, making it look more attractive than it actually is.

A. THE COMPANIES' NATURAL GAS AND ENERGY PRICE FORECASTS ARE [redacted] AND OUTDATED

Q How have natural gas prices and expectations changed since the Companies' valuation of the proposed transaction?

A Both natural gas prices and future expectations have decreased markedly since the Companies' valuation of the proposed transaction. Natural gas prices have averaged $2.69 per MMBtu through November of 2015. Yet ICF predicted a price of $4.34 per MMBtu in 2015 which is an overestimate of 61% (shown in CONFIDENTIAL Table 1). This comparison does not even incorporate more

[8] See Direct Testimony of Judah Rose, Table 9 and Rose confidential workpapers.
[9] Direct Testimony of Tyler Comings, p.13, lines 5-8.

recent drops in natural gas prices in December of 2015, including a 16-year low spot Henry Hub price of $1.65 per MMBtu on December 15th.[10]

NYMEX futures show that the market expects prices to remain below $3 per MMBtu for 2016 and 2017. The ICF price forecast relied upon by the Companies in this proceeding is 70% higher than current market expectations for 2016, and [redacted] for 2017.

CONFIDENTIAL Table 1: ICF Forecast Compared to 2015 Actual Prices and 2016 and 2017 NYMEX Futures[11]

	ICF forecast (used in filing)	Actual (through Nov. 2015) and NYMEX (2016, 2017)	ICF overestimate (%)
2015	$4.34	$2.69	61%
2016	$4.28	$2.51	70%
[redacted]	[redacted]	[redacted]	[redacted]

Q Did you raise the issue that natural gas forecasts were too high previously?

A Yes, I have addressed this issue several times. In my direct testimony (filed on December 22, 2014), I pointed out that the ICF forecasts were already too high for 2015 and 2016.[12] I updated this argument in my supplemental testimony (filed on May 11, 2015) to show that prices and market expectations had decreased since my direct testimony was filed. Each time I have filed testimony (including this time), I point out that natural gas prices and expectations have <u>continued</u> to decrease since the previous filing.

[10] EIA Natural Gas Weekly Update: http://www.eia.gov/naturalgas/weekly/archive/2015/12_17/index.cfm.

[11] Natural gas price in 2015 is the average of Henry Hub spot prices from January through November 2015 reported by EIA (available at: https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm). NYMEX futures are from December 29, 2015 and are attached as Exhibit TFC-43 (downloaded from: http://www.cmegroup.com/trading/energy/natural-gas/natural-gas_quotes_settlements_futures.html). ICF forecast prices are reported in the workpapers of Judah Rose.

[12] Direct Testimony of Tyler Comings, Table 6.

Q **Has ICF produced a more recent forecast that more accurately reflects natural gas price expectations?**

A Yes. In a report for DTE Electric in Michigan, ICF produced a Henry Hub natural gas price forecast in August 2015 that included consideration of EPA's Clean Power Plan--shown in CONFIDENTIAL Figure 2[13]. While this more up-to-date forecast remains higher than actual prices and expectations for 2015 through 2017, it is [redacted] in every year than the ICF forecast used in the Companies' filing.

[redacted]

CONFIDENTIAL Figure 2: Comparison of Natural Gas Price Forecasts ($/MMBtu)[14]

[13] Exhibit A-25, Before the Michigan PSC, Case No.: U-17920, p.17, attached as Exhibit TFC-44 (also available at: https://efile.mpsc.state.mi.us/efile/docs/17920/0024.pdf). Numbers adjusted to nominal dollars based on 2.1% annual inflation.

[14] *Id.* Direct Testimony of Judah Rose, p 87 Attachment II.

Q Are low natural gas prices attracting new natural gas generation in Ohio?

A Yes. Table 2 shows five natural gas plants that are slated to come on-line in the next several years. These plants alone would represent nearly 4 GW of new capacity in Ohio. Four of these five plants (2.8 GW) have been approved by the Ohio Power Siting Board, three are currently under construction, and all have applied for interconnection with PJM.[15] The company applying for approval of one of these facilities cited "abundant, local, low-cost supply of natural gas in the region" as a reason for proposing the plant.[16]

Table 2: New Natural Gas Generation in Ohio[17]

Project Name	Capacity (MW)	Approved by OPSB	Under Construction	Expected operation date
Oregon Clean Energy Center	799	X	X	2017
Carroll County Energy Generation Facility	700	X	X	2017
Clean Energy Future - Lordstown	800	X		2018
Middletown Energy Center	540	X	X	2018
South Field Energy Electric Generation Facility	1,100			2020

Q Has ICF also overestimated energy prices so far this year?

A [redacted]. As shown in CONFIDENTIAL Table 3, ICF has [redacted] 2015 ATSI energy prices by [redacted] and AEP-Dayton Hub prices by [redacted]. Given that natural gas and energy prices are generally correlated, it is unsurprising that ICF's outdated forecast also [redacted] energy prices.[18]

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[15] See Ohio Power Siting Board, Approved Cases (available at: http://www.opsb.ohio.gov/opsb/index.cfm/siting-case-breakdown/approved-cases/). PJM Interconnection Queue (in order listed in Table 2): Y1-069, Y2-050, Z2-028, Z1-079, and AA1-123. (available at: http://www.pjm.com/planning/generation-interconnection/generation-queue-active.aspx)

[16] Lordstown Energy Center Application to the Ohio Power Siting Board, Table 01-1 (available at: http://dis.puc.state.oh.us/TiffToPDf/A1001001A15C23B10630A26755.pdf)

[17] *Id.*

[18] See Direct Testimony of Judah Rose, p.23, Figure 4.

CONFIDENTIAL Table 3: ICF Forecast Compared to 2015 Actual Prices[19]

PJM Zone	Actual 2015 price ($/MWh)	ICF forecast ($/MWh)	ICF [redacted] (%)
ATSI	$32.93	[redacted]	[redacted]
AEP-Dayton	$31.80	[redacted]	[redacted]

Q Have low natural gas and energy prices caused the Sammis plant to operate less frequently in 2015 relative to what the Companies project for the future?

A [redacted] Low natural gas and energy prices—which are correlated—compound to reduce revenue to coal generators in two ways: 1) coal generators are called upon less often because they are less competitive relative to natural gas and 2) less revenue is created for the same amount of energy because prices are lower. Despite these pressures, the Companies continue to [redacted].

CONFIDENTIAL Figure 3 shows that the Sammis plant has operated at a 57% capacity factor from 2010 through 2014 and 47% through October of 2015.[20] The Companies had previously projected that Sammis would operate at an [redacted] capacity factor in 2015, which is [redacted] given actual data available in 2015.[21] From 2016 through 2024, the Companies are projecting that the plant will operate at an average capacity factor of [redacted].

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[19] ICF forecast prices are all-hours averages from Data Response to SC Set 1- RPD-28 Attachment 1 – Confidential. ATSI and AEP-Dayton hub prices are an all-hours average through December 18, 2015 (available at: http://www.pjm.com/markets-and-operations/energy/day-ahead/lmpda.aspx).
[20] Net plant generation from EIA's Electricity Data Browser, Plant level data report, Monthly net generation through October 2015 (available at: http://www.eia.gov/electricity/data/browser/.)
[21] SC Set 1 INT-10, Attachment 1-Competitively Sensitive Confidential.

[redacted]

CONFIDENTIAL Figure 3: Sammis Historical and Projected Capacity Factor (%)[22]

Q Have you updated the energy revenue estimate generated by Sammis for 2015 so far?

A Yes. In my supplemental testimony, I presented estimates of Sammis energy market revenue compared to what the Companies had projected for 2015.[23] Using more up-to-date operational data available through September 2015, I now project that the Companies will have [redacted] 2015 revenue from the Sammis plant by [redacted]. (The Sammis plant is on track to generate [redacted] in energy

[22] Net plant generation from EIA's Electricity Data Browser, Plant level data report, Monthly net generation through October 2015 (available at: http://www.eia.gov/electricity/data/browser/.) Companies' projection is from workpapers of Jason Lisowski.
[23] Supplemental Testimony of Tyler Comings, p.12.

revenue [redacted].[24]) This represents a [redacted] of energy revenue for 2015.

Q Are the Companies also predicting that the OVEC plants will run more in the future than they have in 2015?

A [redacted]. Kyger Creek and Clifty Creek have operated at a 51% capacity factor through October 2015 (using the latest data available).[25] The Companies had projected that the OVEC units would operate at [redacted] in 2015 which is [redacted] given the performance through October. The Companies are predicting that the plants will run an average of [redacted] from 2016 through 2024. As with Sammis, the Companies expect the OVEC plants will [redacted] in the future [redacted] performance and the underlying causes of that performance—namely low natural gas and energy prices.

Q How is data for 2015 relevant to the proposed transaction, which begins in 2016?

A Comparing actual data to forecasts for 2015 shows that the Companies have significantly overvalued the proposed transaction and continue to do so. The 2015 data provides further evidence that the [redacted] projected by the Companies and FES under the proposed transaction are likely to be [redacted] than projected, and that it is even less likely that the proposed transaction would [redacted] over the eight year term.

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[24] The Companies' energy revenue projection for Sammis [redacted] is from SC Set 1-INT-16, Attachment 1 - Competitively Sensitive Confidential for 2015. My revenue estimate is based on actual hourly generation and prices through September 2015 (the latest hourly generation data available). The annualized 2015 result is based on revenue from January through September and number of hours [redacted] = [redacted]*(8760 hours in a year)/(6552 hours from January through September).Gross unit generation from EPA's Air Markets Program Data is available at: http://ampd.epa.gov/ampd/. Net plant generation is pulled from EIA's Electricity Data Browser, Plant level data report (available at: http://www.eia.gov/electricity/data/browser/. Hourly energy prices are pulled from PJM (available at: http://www.pjm.com/markets-and-operations/energy/real-time/lmp.aspx.)

[25] Net plant generation from EIA's Electricity Data Browser, Plant level data report, Monthly net generation through October 2015 (available at: http://www.eia.gov/electricity/data/browser/.) Companies' projection is from workpapers of Jason Lisowski.

Q Given recent market data on natural gas and energy prices, is the proposed transaction overvalued from the ratepayers perspective?

A Yes. The Companies' valuation of the proposed transaction is predicated on natural gas and energy price expectations that are [redacted] and outdated. These expectations have led the Companies to conclude that the plants involved in the transaction are more competitive than they actually are or that they can reasonably expect to be over the eight year term of the proposed transaction.

At a minimum, the Companies should be required to provide up-to-date forecasts of market energy and natural gas prices, and of other key assumptions, so that the likely customer impacts of the proposed eight year transaction can be projected and evaluated on the basis of expected market conditions today, rather than on the basis of stale and [redacted] biased information. Relying on forecasts of key assumptions that were performed almost two years ago, and that are already proving to be wrong, is unacceptable.

B. THE COMPANIES' CAPACITY PRICE FORECASTS ARE [redacted] AND OUTDATED

Q Is the capacity price forecast used by the Companies reasonable?

A No. I stated in my direct testimony that it was unreasonable for the Companies to assume that capacity prices will [redacted].[26] Since then, PJM has adopted a Capacity Performance (CP) standard that (all else equal) would lead to capacity price increases and lower load forecasts that would decrease prices (all else equal). However, even with the new CP standard, the actual PJM capacity auction results for the 2018/2019 delivery year were much [redacted] than the Companies anticipated: $165 per MW-day [redacted] (shown in CONFIDENTIAL Figure 4).[27] The Companies have not updated the valuation to reflect these new results. They have also not reflected

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[26] Direct Testimony of Tyler Comings, p.29, lines 8-14.

[27] PJM BRA results (available at: http://www.pjm.com/~/media/879A2FA2A1794C7887A98686A70336D2.ashx). Companies' capacity price projections are presented in Lisowski's workpapers.

any changes to capacity revenue from the transitional auctions for 2016/2017 and 2017/2018.

As shown below, the historical capacity prices can be volatile from year to year. [redacted], historical PJM prices have never maintained a high price level for more than a year or two. The Synapse capacity price forecast was [redacted] the actual 2018/2019 result—I projected $176 per MW-day and the result was $165 per MW-day. While my forecast is still likely too high for the future auctions, it is [redacted] than the forecast used by the Companies.

[redacted]

CONFIDENTIAL Figure 4: Past PJM Auction Results through 2018/2019, and Companies' Projected Capacity Price ($/MW-day)[28]

[28] *Id.*

Q Is PJM considering changes to the capacity market that would put downward pressure on capacity prices?

A Yes. All else equal, a decrease in peak load requirement would lead to a lower capacity price. As I have discussed previously, the Companies relied on the 2014 PJM load forecast. Since then, PJM released a 2015 load forecast that was lower than its 2014 forecast.[29] In the latest 2016 forecast, PJM has updated its methodology yet again. For this latest forecast, PJM states that it is now accounting for "trends in equipment/appliance saturation and efficiency, and distributed solar generation…"[30]

As a result of this new methodology (shown below in Figure 5), 2016 peak load forecasts for the region are 3.7% lower in 2016 and 5.7% lower in 2024.[31] The Companies rely on outdated load forecasts from February 2014 that lead them to overstate load requirements and, as a result, [redacted] capacity and energy prices.

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[29] Supplemental Testimony of Tyler Comings, p.15, line 16 through p.16.
[30] PJM 2016 Load Forecast, p.1, attached as Exhibit TFC-45 (also available at: http://www.pjm.com/~/media/documents/reports/2016-load-report.ashx).
[31] PJM Load Forecast Reports from 2014 through 2016, Table B-1. Load Forecast (available at: http://www.pjm.com/~/media/documents/reports/2016-load-report.ashx)

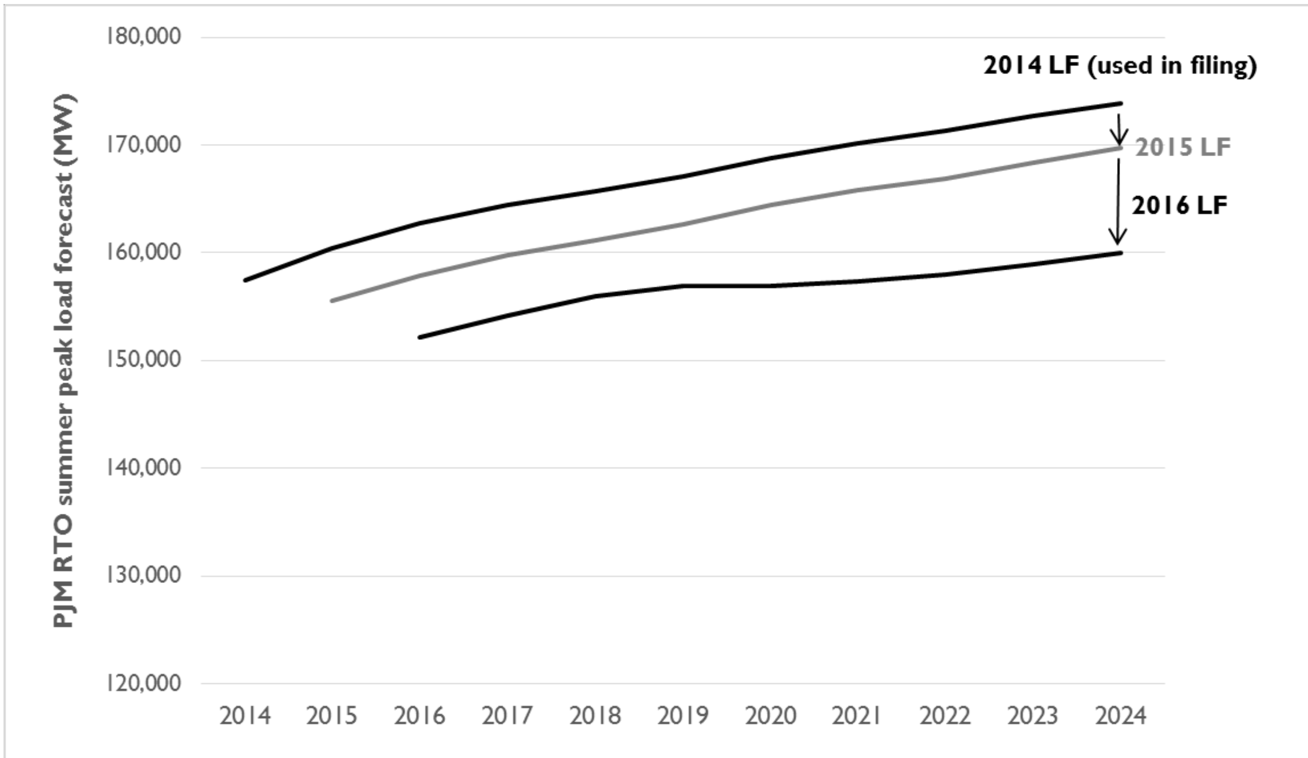

Figure 5: PJM's 2014-2016 Gross Peak Load Forecasts ("LF")

Q **Given the use of outdated forecasts, should the proposed transaction be pursued at this time?**

A No. The Companies have used stale forecasts that are approaching two years old. Importantly, in the case of natural gas, energy, and capacity prices, they are biased towards overvaluing the transaction. The Companies should at a bare minimum update the assumptions to reflect recent market trends. I have testified previously that the Companies' analysis was likely overstated, but as actual data has become available it is even more apparent that their analysis simply cannot be supported.

IV. FINDINGS AND RECOMMENDATIONS

Q What are your findings?

A The Companies and I agree that ratepayers will bear significant costs in the first 31 months of the transaction. Where we differ is whether ratepayers will ever recover from these losses. I find that:

1. Under the Companies' expectations, ratepayers will pay $364 million in the first 31 months of the proposed transaction (June 1, 2016 through December 31, 2018).

2. Under FES's expectations, ratepayers will [redacted] over the same period, and [redacted] during the eight year transaction. Thus the seller (FES) values the transaction [redacted] than the buyer (the Companies). In any type of transaction, a value [redacted] of this sort is a red flag—and should especially be so as the risk is being shifted from FES shareholders to the Companies' customers.

3. Ratepayers are unlikely to recover from these predicted losses. The Companies have not updated key factors that have markedly changed since the filing. This has led them to significantly overvalue the transaction. Unfortunately, ratepayers would suffer as a result of this oversight.

Q What are your recommendations?

A For reasons discussed above, I recommend that the Rider RRS be denied.

Q Does this conclude your testimony?

A Yes, it does. However, I reserve the right to update or supplement my testimony based on new information that may become available.

CERTIFICATE OF SERVICE

I hereby certify that on this date I served a copy of the foregoing Third Supplemental Testimony of Tyler Comings (Redacted version) upon the following parties via electronic mail.

Date: December 30, 2015

s/ Shannon Fisk
Shannon Fisk

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Month	Open	High	Low	Last	Change	Settle	Estimated Volume	Prior Day Open Interest
JAN 16	2 238	2 387	2.235	2.372	+.144	2.372	12,457	5,814
FEB 16	2 267	2 386	2.257	2.317	+.114	2.370	176,047	286,042
MAR 16	2 309	2.414	2.303	2.349	+.096	2.397	68,473	211,725
APR 16	2 342	2.426	2.339	2.376	+.075	2.411	44,120	107,533
MAY 16	2 383	2.466	2.383	2.417A	+.068	2.451	17,233	67,189
JUN 16	2.429	2 510	2.422	2.455	+.061	2.491	12,378	38,816
JLY 16	2.490	2 558	2.479	2.499	+.058	2.535	10,933	28,012
AUG 16	2 514	2 576	2.513	2.514A	+.054	2.551	5,756	22,964
SEP 16	2 509	2 573	2.498A	2.512	+.051	2.547	4,138	44,940
OCT 16	2 519	2 593	2.519	2.535	+.051	2.569	13,553	58,633
NOV 16	2.605	2.671	2.605	2.615A	+.040	2.642	2,231	14,732
DEC 16	2.765	2 830	2.765	2.770A	+.033	2.795	2,945	16,735
JAN 17	2 887	2 935	2.871	2.872A	+.029	2.896	3,170	26,540
FEB 17	2 913	2 925	2.867	2.867	+.026	2.886	473	5,664
MAR 17	2 875	2 895	2 837A	2.837A	+.025	2.857	849	12,975
APR 17	2.697	2.737	2.673	2.673	+.015	2.692	334	11,245
MAY 17	2.684	2.724B	2.683	2.683	+.013	2.701	28	3,152
JUN 17	2.740	2.763	2.725	2.725	+.011	2.741	92	2,896
JLY 17	2.797	2.798	2.785	2.785	+.011	2.786	5	2,377
AUG 17	-	2.790B	-	2.790B	+.011	2.798	7	2,582
SEP 17	2.790	2.795	2.790	2.790A	+.010	2.790	8	2,203
OCT 17	2 877	2 878	2.796A	2.796A	+.010	2.808	44	2,763
NOV 17	2 969	2 969	2.842	2.855	+.010	2.878	22	2,700
DEC 17	3.105	3.109	3 015A	3.015A	+.009	3.023	6	3,784
JAN 18					+.008	3.117	52	1,908

JAN 18	-	-	-	-	+.008	3.117	52	1,908
FEB 18	-	-	-	-	+.006	3.107	0	1,270
MAR 18	3 050	3 050	3.050	3.050	+.005	3.049	1	1,062
APR 18	-	2.785B	-	2.785B	-.005	2.779	0	1,724
MAY 18	-	-	-	-	-.005	2.775	0	783
JUN 18	-	-	-	-	-.005	2.808	0	925
JLY 18	-	-	-	-	-.005	2.845	0	872
AUG 18	-	-	-	-	-.005	2.859	0	840
SEP 18	-	-	-	-	-.006	2.853	0	755
OCT 18	-	-	-	-	-.006	2.879	0	829
NOV 18	-	-	-	-	-.006	2.955	12	669
DEC 18	-	-	-	-	-.006	3.110	12	1,849
JAN 19	-	-	-	-	-.006	3.212	12	843
FEB 19	-	-	-	-	-.007	3.203	12	489
MAR 19	-	-	-	-	-.009	3.148	12	475
APR 19	-	-	-	-	-.016	2.893	0	588
MAY 19	-	-	-	-	-.016	2.888	0	464
JUN 19	-	-	-	-	-.016	2.921	0	469
JLY 19	-	-	-	-	-.016	2.957	0	502
AUG 19	-	-	-	-	-.016	2.974	0	578
SEP 19	-	-	-	-	-.016	2.968	0	460
OCT 19	-	-	-	-	-.015	2.996	0	436
NOV 19	-	-	-	-	-.015	3.076	0	391
DEC 19	-	-	-	-	-.015	3.241	0	484
JAN 20	3 360	3 360	3.360	3.360	-.015	3.356	1	194
FEB 20	-	-	-	-	-.016	3.347	0	83
MAR 20	-	-	-	-	-.017	3.293	0	103
APR 20	-	-	-	-	-.017	3.033	0	132
MAY 20	-	-	-	-	-.017	3.028	0	73
JUN 20	-	-	-	-	-.017	3.060	0	70
JLY 20	-	-	-	-	-.017	3.094	0	122
AUG 20	-	-	-	-	-.017	3.118	0	65
SEP 20	-	-	-	-	-.017	3.113	0	77
OCT 20	-	-	-	-	-.017	3.143	0	63
NOV 20	-	-	-	-	-.017	3.223	0	61
DEC 20	-	-	-	-	-.017	3.390	0	308
JAN 21	-	-	-	-	-.017	3.508	0	53
FEB 21	-	-	-	-	-.017	3.498	0	52
MAR 21	-	-	-	-	-.015	3.440	0	52
APR 21	-	-	-	-	-.015	3.155	0	52
MAY 21	-	-	-	-	-.015	3.150	0	53
JUN 21	-	-	-	-	-.015	3.180	0	52
JLY 21	-	-	-	-	-.015	3.217	0	52
AUG 21	-	-	-	-	-.015	3.249	0	52
SEP 21	-	-	-	-	-.015	3.249	0	52

OCT 21	-	-	-	-	-.015	3.286	0	53
NOV 21	-	-	-	-	-.015	3.366	0	52
DEC 21	-	-	-	-	-.015	3.536	0	52
JAN 22	-	-	-	-	-.015	3.656	0	0
FEB 22	-	-	-	-	-.015	3.645	0	0
MAR 22	-	-	-	-	-.015	3.583	0	1
APR 22	-	-	-	-	-.015	3.293	0	0
MAY 22	-	-	-	-	-.015	3.288	0	1
JUN 22	-	-	-	-	-.015	3.318	0	0
JLY 22	-	-	-	-	-.015	3.356	0	1
AUG 22	-	-	-	-	-.015	3.392	0	1
SEP 22	-	-	-	-	-.015	3.398	0	0
OCT 22	-	-	-	-	-.015	3.440	0	0
NOV 22	-	-	-	-	-.015	3.520	0	0
DEC 22	-	-	-	-	-.015	3.692	0	0
JAN 23	-	-	-	-	-.015	3.815	0	0
FEB 23	-	-	-	-	-.015	3.802	0	0
MAR 23	-	-	-	-	-.015	3.739	0	1
APR 23	-	-	-	-	-.015	3.444	0	0
MAY 23	-	-	-	-	-.015	3.437	0	1
JUN 23	-	-	-	-	-.015	3.467	0	0
JLY 23	-	-	-	-	-.015	3.505	0	0
AUG 23	-	-	-	-	-.015	3.541	0	0
SEP 23	-	-	-	-	-.015	3.551	0	0
OCT 23	-	-	-	-	-.015	3.599	0	4
NOV 23	-	-	-	-	-.015	3.679	0	0
DEC 23	-	-	-	-	-.015	3.853	0	0
JAN 24	-	-	-	-	-.015	3.976	0	0
FEB 24	-	-	-	-	-.015	3.961	0	0
MAR 24	-	-	-	-	-.015	3.897	0	0
APR 24	-	-	-	-	-.015	3.587	0	0
MAY 24	-	-	-	-	-.015	3.577	0	1
JUN 24	-	-	-	-	-.015	3.607	0	0
JLY 24	-	-	-	-	-.015	3.645	0	0
AUG 24	-	-	-	-	-.015	3.681	0	0
SEP 24	-	-	-	-	-.015	3.692	0	0
OCT 24	-	-	-	-	-.015	3.742	0	8
NOV 24	-	-	-	-	-.015	3.824	0	0
DEC 24	-	-	-	-	-.015	4.002	0	0
JAN 25	-	-	-	-	-.015	4.127	0	0
FEB 25	-	-	-	-	-.015	4.111	0	0
MAR 25	-	-	-	-	-.015	4.046	0	0
APR 25	-	-	-	-	-.015	3.721	0	0
MAY 25	-	-	-	-	-.015	3.706	0	0
JUN 25	-	-	-	-	-.015	3.741	0	0

JUN 25	-	-	-	-	-.015	3.741	0	0
JLY 25	-	-	-	-	-.015	3.786	0	0
AUG 25	-	-	-	-	-.015	3.826	0	0
SEP 25	-	-	-	-	-.015	3.839	0	0
OCT 25	-	-	-	-	-.015	3.894	0	0
NOV 25	-	-	-	-	-.015	3.979	0	0
DEC 25	-	-	-	-	-.015	4.159	0	0
JAN 26	-	-	-	-	-.015	4.284	0	0
FEB 26	-	-	-	-	-.015	4.262	0	0
MAR 26	-	-	-	-	-.015	4.189	0	0
APR 26	-	-	-	-	-.015	3.839	0	0
MAY 26	-	-	-	-	-.015	3.824	0	0
JUN 26	-	-	-	-	-.015	3.859	0	0
JLY 26	-	-	-	-	-.015	3.904	0	0
AUG 26	-	-	-	-	-.015	3.944	0	0
SEP 26	-	-	-	-	-.015	3.957	0	0
OCT 26	-	-	-	-	-.015	4.012	0	0
NOV 26	-	-	-	-	-.015	4.112	0	0
DEC 26	-	-	-	-	-.015	4.312	0	0
JAN 27	-	-	-	-	-.015	4.437	0	0
FEB 27	-	-	-	-	-.015	4.415	0	0
MAR 27	-	-	-	-	-.015	4.342	0	0
APR 27	-	-	-	-	-.015	3.962	0	0
MAY 27	-	-	-	-	-.015	3.947	0	0
JUN 27	-	-	-	-	-.015	3.982	0	0
JLY 27	-	-	-	-	-.015	4.027	0	0
AUG 27	-	-	-	-	-.015	4.067	0	0
SEP 27	-	-	-	-	-.015	4.082	0	0
OCT 27	-	-	-	-	-.015	4.137	0	0
NOV 27	-	-	-	-	-.015	4.252	0	0
DEC 27	-	-	-	-	-.015	4.477	0	0
JAN 28	-	-	-	-	-.015	4.602	0	0
FEB 28	-	-	-	-	-.015	4.577	0	0
MAR 28	-	-	-	-	-.015	4.504	0	0
APR 28	-	-	-	-	-.015	4.124	0	0
MAY 28	-	-	-	-	-.015	4.109	0	0
JUN 28	-	-	-	-	-.015	4.144	0	0
JLY 28	-	-	-	-	-.015	4.189	0	0
AUG 28	-	-	-	-	-.015	4.229	0	0
SEP 28	-	-	-	-	-.015	4.244	0	0
OCT 28	-	-	-	-	-.015	4.299	0	0
NOV 28	-	-	-	-	-.015	4.414	0	0
DEC 28	-	-	-	-	-.015	4.639	0	0
Total							375,416	1,003,678

Last Updated: Tuesday, 29 Dec 2015 10:32 PM

About This Report

Impact of the NEXUS Pipeline On Michigan Energy Markets

November 2015

Submitted to:
DTE Electric

Submitted by:
ICF Resources, L.L.C.
9300 Lee Highway
Fairfax, VA 22031

ICF INTERNATIONAL

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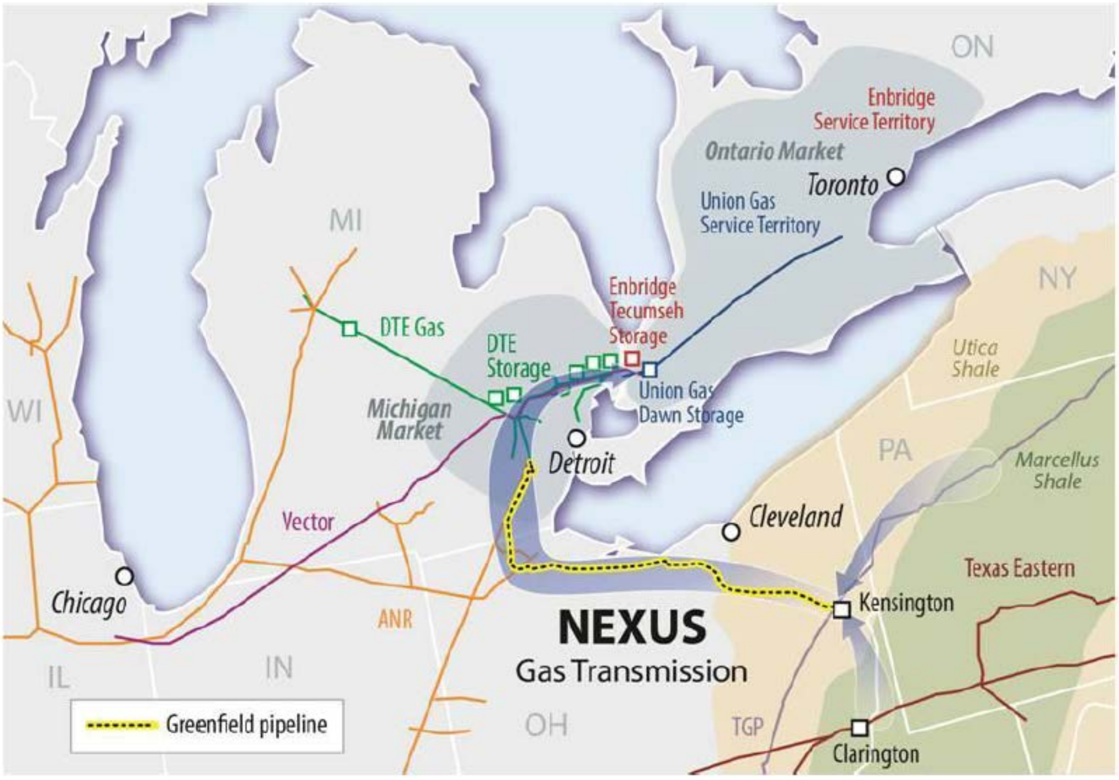
1 Introduction

1.1 Purpose

ICF was engaged by DTE Electric to assess the impacts of the NEXUS Gas Transmission (NEXUS) pipeline project on natural gas and power markets in Michigan. The NEXUS Pipeline project is proposed by Spectra Energy and DTE Energy to move new Appalachian shale gas production to markets in the U.S. Midwest, including Ohio, Michigan, and Chicago, and Ontario, Canada. The new pipeline will serve local distribution companies, power generators and industrial users in these markets.

As shown in Exhibit 1-1, the NEXUS Pipeline would consist of about 250 miles of large diameter pipe, beginning in eastern Ohio and extend northwesterly to interconnect with the DTE Gas Transmission System and Vector pipeline. The proposed pipeline would deliver natural gas produced in the Marcellus and Utica plays of the Appalachian Basin directly to gas markets in Michigan and Ontario.

Exhibit 1-1: Proposed NEXUS Pipeline Route



DTE Electric has signed a precedent agreement for 30,000 Dth/day of capacity on the NEXUS Pipeline starting November 2017, and increasing to 75,000 Dth/day of capacity after completion of a new combined cycle facility that is expected to be completed in 2022. The agreement term is fifteen years after the increase to 75,000 Dth/day, which is expected to be through 2037.

1.2 Rationale for the NEXUS Pipeline

Fundamental changes in North American natural gas markets are driving the decision to build and contract for NEXUS capacity.

The shale gas revolution has greatly increased the availability of low cost natural gas supply. While there are economic shale gas plays in a variety of regions (including Western Canada, the Gulf Coast and the Mid-Continent), the majority of the production growth is expected to occur in the Marcellus and Utica shale plays in the Northeastern U.S.

On the demand side, the widespread availability of low cost natural gas, and changes in environmental regulations are driving rapid growth in demand, for power generation, industrial demand, LNG exports, and exports to Mexico. Much of the industrial and export-driven demand is concentrated along the Gulf Coast. Natural gas demand in western Canada (for power generation, oil sands production and LNG exports) is also expected to increase.

The shifts in the location of production and demand, as well as the rapid growth in production and demand have led to a fundamental restructuring of the natural gas transportation and distribution system in North America, and have resulted in widespread changes in natural gas production and transportation patterns that are changing the economics of purchasing natural gas in different supply basins. The most significant changes are occurring in the U.S. Northeast, where production from the Marcellus and Utica basins is displacing natural gas production from other regions.

The NEXUS Pipeline is consistent with these continuing market changes in that it provides an outlet for Appalachian shale gas production, as well as providing an additional source of natural gas into Michigan markets to meet expected growth in Michigan natural gas requirements in the power sector.

1.3 Summary of Conclusions

ICF has evaluated the impact of the proposed NEXUS Pipeline on both natural gas and wholesale power markets in Michigan. Based on this analysis, ICF projects that construction of the NEXUS Pipeline should result in a significant reduction in both natural gas and wholesale power costs in Michigan:

- Construction of the NEXUS Pipeline is expected to lead to an average reduction in natural gas prices at the MichCon Citygate of $0.21 per MMBtu, relative to the scenario without the NEXUS Pipeline capacity, over the 20 year period of the DTE Electric contract for NEXUS Pipeline Capacity (2018 through 2037[1]).
- The decline in Michigan natural gas prices is expected to lead to a reduction in natural gas costs of more than $1.9 billion to Michigan natural gas consumers other than power generators, including residential, commercial, and industrial natural gas consumers over the 20 year period of the NEXUS Pipeline contract.
    - The projected savings to residential, commercial, and industrial natural gas consumers over the 20 year period have a net present value (NPV) of $0.8 billion.
- The decline in Michigan natural gas prices is projected to lead to a reduction in

[1] The DTE Electric NEXUS Pipeline contract runs from November 2017 through October 2037. ICF's IPM model runs on a calendar year basis. Hence ICF's analysis covers the 20 year period from January 2018 through December 2037.

Michigan gas-fired generation production costs of about $1.2 billion over the 20 year period of the NEXUS Pipeline contract.

- The projected reductions in gas-fired generation production costs over the 20 year period have a net present value of $0.5 billion.

Overall, the net impact of the NEXUS Pipeline on Michigan natural gas and wholesale power costs is expected to be more than $3.1 billion[2] over the 20 year life of the DTE Electric contract for NEXUS capacity, with a net present value of more than $1.3 billion.[3]

1.3.1 Impact on DTE Electric Gas Supply Costs of Holding Capacity on NEXUS Pipeline

The $3.1 billion in net savings identified above are due to the availability of the NEXUS Pipeline, and will occur as long as the pipeline is built regardless of whether or not DTE Electric contracts for capacity on the pipeline. However, the DTE Electric agreement for NEXUS Pipeline capacity has two major additional benefits.

- The DTE Electric agreement increases the likelihood that the pipeline will be developed, hence is important in ensuring that the benefits identified for the Pipeline are achieved.
- The DTE Electric agreement is expected to result in additional reductions in natural gas supply costs for DTE Electric that will exceed the cost of the contract.

Holding capacity on NEXUS will enable DTE Electric to purchase natural gas directly from the Marcellus and Utica basins at prices that are significantly lower than prices in Michigan. Prices at the NEXUS receipt point at Kensington are projected to average $0.92 per MMBtu below the price of natural gas at the NEXUS delivery point at the MichCon Citygate. After accounting for capacity and fuel costs on the NEXUS Pipeline, ICF projects the delivered cost of gas on the NEXUS system to be on average $0.13 per MMBtu lower than the MichCon Citygate price of gas, generating a natural gas cost savings of about $79 million for the NEXUS Pipeline capacity contracted for by DTE Electric over the 20 year contract period. These cost savings have an NPV of about $22 million.

1.4 Overview of Approach

For this analysis, ICF utilized a suite of analytical tools, including its Gas Market Modeling (GMM©) and Integrated Planning Model (IPM®).

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[2] The total benefits of $3.1 billion include the $1.9 billion in savings to residential, commercial and industrial natural gas consumers, plus the $1.2 billion reduction in power generation natural gas cost savings.

[3] All net present value savings are discounted to the start of 2018 using a discount rate of 7.1%.

Exhibit 1-2: Analytic Process

Source: ICF

Modeling assumptions are drawn from ICF's August 2015 natural gas and power market analyses, which incorporate the recently finalized Clean Power Plan (CPP) rules. The GMM, an internationally recognized model of the North American gas market, includes projections for natural gas demand by sector, conventional and unconventional natural gas resources, production costs, and other major gas market developments, such as potential LNG exports. The IPM model simulates forward power markets including capacity expansion and generator dispatch. The gas and power models are integrated through an iterative process where the natural gas prices are passed to the IPM model and the IPM's power sector natural gas demand is passed back to the GMM; the process is complete when the two models reach consistent gas demand and price solutions.

For the natural gas market analysis, ICF examined four scenarios:

1) With Rover Pipeline Only (CPP Case August 2015, Rover Pipeline added)
2) With NEXUS and Rover Pipelines (CPP Case August 2015, both Rover and NEXUS capacity added)
3) No Pipeline Added (CPP Case August 2015, Rover and NEXUS expansions turned off)
4) With NEXUS Pipeline Only (CPP Case August 2015, NEXUS Pipeline added

Given the current status of the Rover Pipeline, including the filing status at FERC, and the level of contracted capacity on the pipeline, we consider it likely that the Rover Pipeline will proceed. As a result, our analysis focuses primarily on scenarios 1 and 2, which include the Rover Pipeline with and without the NEXUS Pipeline.

The natural gas market analysis examines the impact of incremental pipeline capacity additions on gas prices in the Michigan market and upstream points in the Marcellus and Utica shale area. Natural gas cost savings to Michigan consumers due to the reduction in natural gas prices, with and without the proposed DTE Electric contract for capacity on the NEXUS Pipeline, are also estimated in this analysis

For the wholesale power market analysis, the gas prices resulting from the With Rover Pipeline (scenario 1) and the With NEXUS and Rover Pipeline (scenario 2) are considered for purposes of determining the impact of the NEXUS Pipeline to wholesale power markets in Michigan.

1.5 Structure of Report

Section 2 of this report provides a broad overview of ICF's long term natural gas market outlook, focusing on the changes in the North American natural gas markets driving the development of the NEXUS Pipeline, and impacting gas supplies in Michigan. Section 3 provides an overview of Michigan power markets and the larger Midcontinent Independent System Operator (MISO) marketing within which DTE Electric operates. This section included discussion of changes in power markets resulting from changing regulatory and market structures. The overall impacts of the NEXUS Pipeline on the Michigan energy markets and DTE Electric are described in Section 4 of the report.

2 Natural Gas Markets: Projected Conditions and Impacts of NEXUS

This section of the report discusses projected natural gas market conditions and impacts of the proposed NEXUS Pipeline on Michigan's gas market. First, we present an overview of ICF's outlook for the North American natural gas market. The North American market has undergone dramatic changes in the past ten years, primarily driven by the growth of new shale gas supplies in the U.S. As these new supplies continue to grow, the market will continue to evolve in response. Second, we focus on the Michigan gas market and the impacts of NEXUS Pipeline, examining the potential shifts in inter-regional pipeline flows and natural gas prices in the context of the constantly evolving North American market.

2.1 North American Natural Gas Market Outlook

With the advent of new shale gas supplies, the North American natural gas market has changed dramatically in the past ten years. Prior to the rise of shale gas, U.S. consumption was increasing more quickly than production, and as a result gas prices were relatively high and volatile. As gas prices increased, investments were made to develop new supplies, such as coal-bed methane, building liquefied natural gas (LNG) import terminals, and – most importantly – in new technologies to tap the vast natural gas reserves found in shale formations.

While it had been long known that there were large deposits of gas and oil in shale formations, it was not until the early 2000s that techniques were developed to economically tap these reserves. The new combination of directional drilling and hydraulic fracturing techniques were first applied in the Barnett Shale in north Texas, but quickly spread to other regions. The first successful shale well in the Marcellus Shale (which stretches from West Virginia through Northeastern Pennsylvania) was drilled in 2004, but Marcellus production did not reach significant levels until 2010. Shale gas development has also spread to the Utica Shale, an over-lapping play that extends into eastern Ohio. Since 2004, nearly 13,000 wells have been drilled in the Marcellus and Utica shale (Exhibit 2-1). In its latest Drilling Productivity Report, EIA estimates combined production from these two plays reached 19 billion cubic feet per day (Bcfd) by mid-2015.[4]

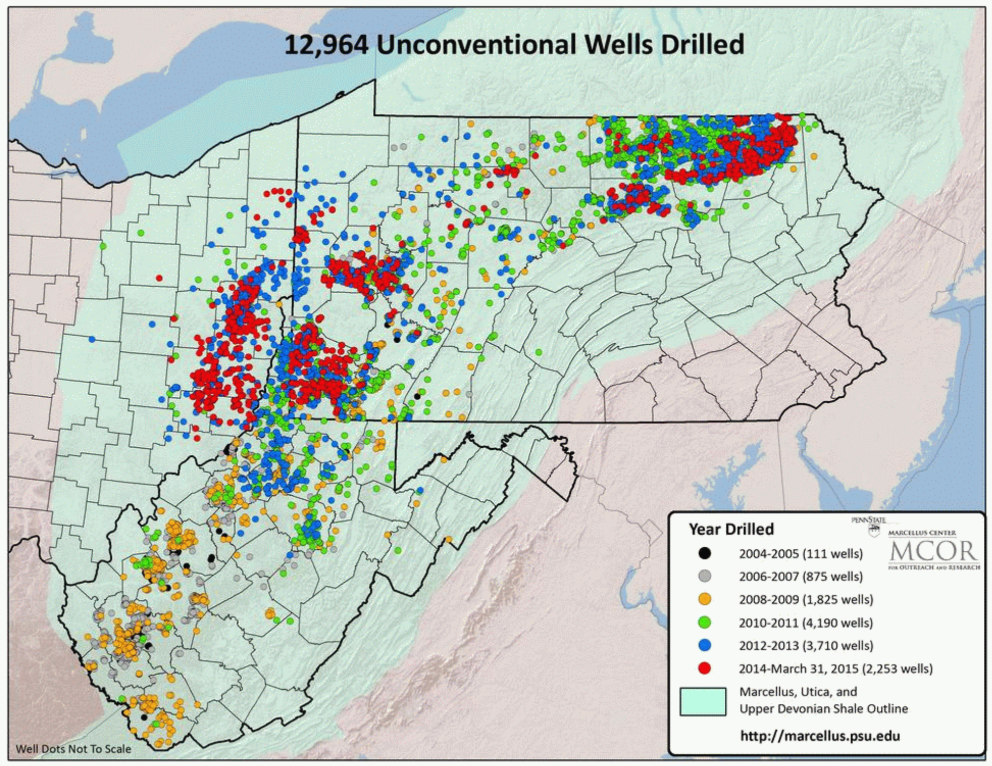
Total U.S. and Canadian gas production is currently about 92 Bcfd, meaning that Marcellus/Utica now accounts for about 20% of total North American production (Exhibit 2-2). Production growth has been center in the Marcellus/Utica due to the size of the resource (estimated to be well over 1,000 trillion cubic feet) and low per-unit production costs. Recent declines in oil and gas prices have resulted in a slow-down in drilling rig activity across North America, including in the Marcellus/Utica area. Between January and September of 2015, the number of active drilling rigs in the Marcellus and Utica plays declined by 45%.[5] Despite the decline in rig activity, Marcellus/Utica production has continued to increase due to improvements in well productivity (i.e., more gas produced per well drilled). ICF projects Marcellus/Utica production will reach 42 Bcfd (about 31% of total North American production) by 2037. While other shale plays are also increasing,

[4] Drilling Productivity Report, U.S. Energy Information Administration, August 2015.

[5] "Gas rigs still at record low: Baker Hughes." Platts Gas Daily, September 8, 2015.

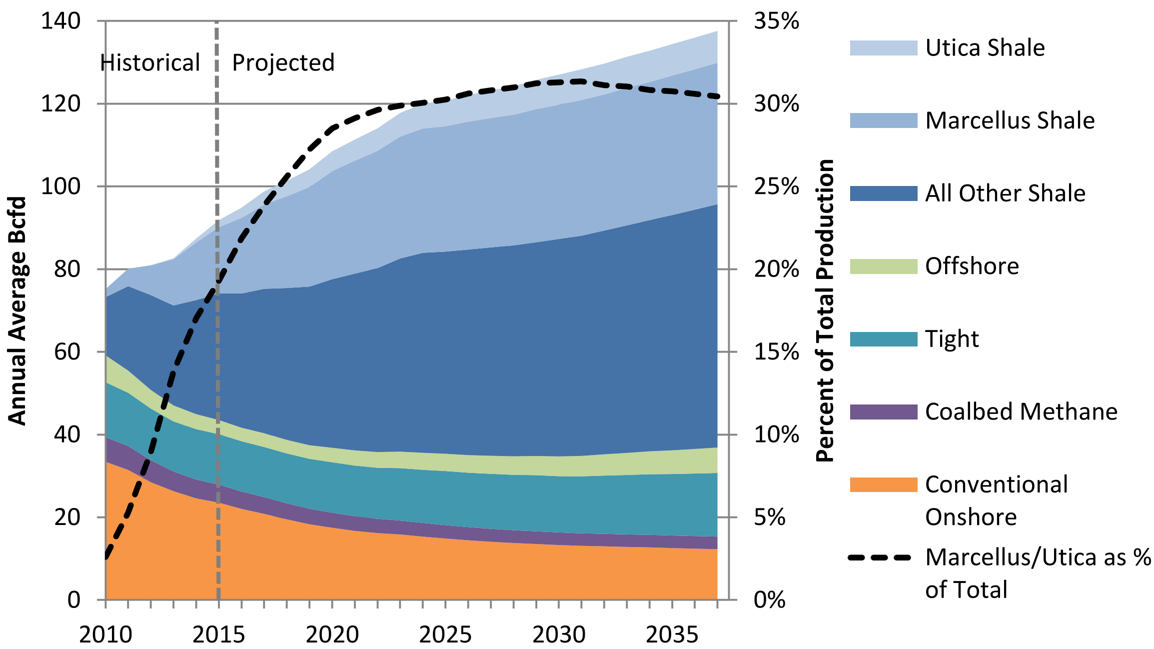
Marcellus/Utica accounts for over half (55%) of the projected production growth from 2015 through 2037.

Exhibit 2-1: Marcellus and Utica Shale Drilling Activity, 2004 through 2015



Source: Pennsylvania State University, Marcellus Center for Outreach and Research

Exhibit 2-2: U.S. and Canada Natural Gas Production



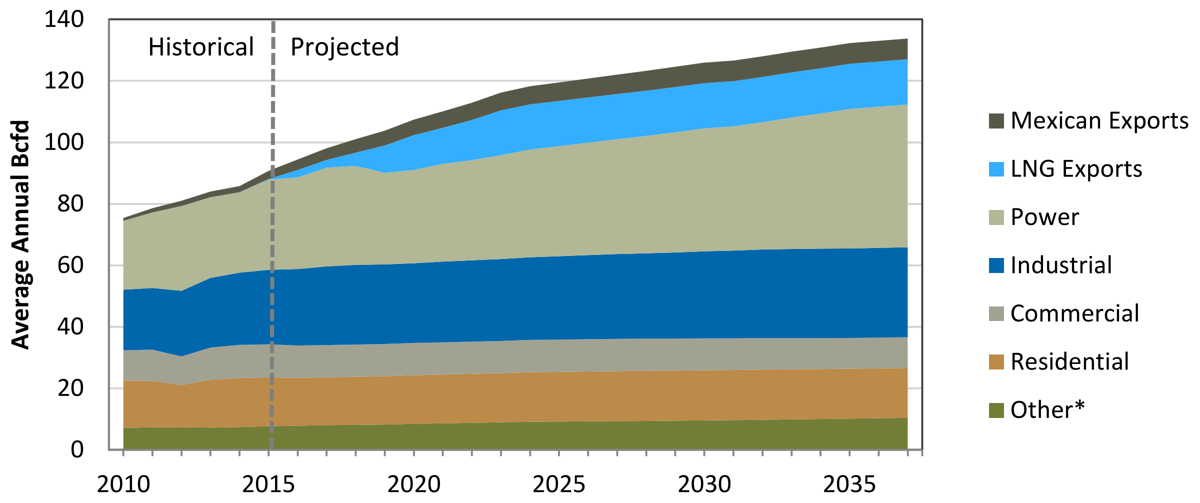
Source: ICF GMM® CPP Case, August 2015

The rapid growth of Marcellus/Utica production encourages continued growth in gas consumption and exports from North America. Through 2020, growth in North America demand is primarily export driven (Exhibit 2-3), and the majority of the expected exports are via LNG terminals (Exhibit 2-4). Since 2012, the U.S. DOE has approved applications for LNG exports from nine U.S. LNG terminals; the majority of these facilities are planned for the Gulf Coast, and one terminal (Cheniere's Sabine Pass) is expected to start exporting by the end of 2015. In Canada, the National Energy Board (NEB) has approved ten proposals for export terminals located on the British Columbia coast. ICF's current projection assumes total North American LNG exports reach 14.7 Bcfd by 2025, with the majority (11.6 Bcfd) coming from the U.S. Gulf Coast. In additional to LNG, pipeline exports to Mexico have also been increasing to meet growing power generation gas demand. By 2030, ICF projects that pipeline export to Mexico will reach 6.7 Bcfd, or roughly triple the 2014 export volumes.

The power generation sector has been and will continue to be the major driver of incremental gas consumption within North America. The growth in power sector gas consumption is driven by multiple factors, including the favorable economics of gas-fired generation, pre-existing environmental regulation (such as Mercury and Air Toxic Standards), and the new Clean Power Plan (CPP) which encourage the retirement of coal plants. By 2037, power sector gas demand is projected to reach 46 Bcfd, or about 35% of total North American demand.

Gas demand is also expected to grow in other sectors, but at a more modest pace. Industrial demand is projected to increase by about 20% through 2037, primarily due to increases in petrochemicals industries which are concentrated on the U.S. Gulf Coast. Residential and commercial gas demands are expected to rise only slightly, as increased demand due to the addition of new gas customers is partially offset by reductions in per-customer consumption due to energy efficiency improvements.

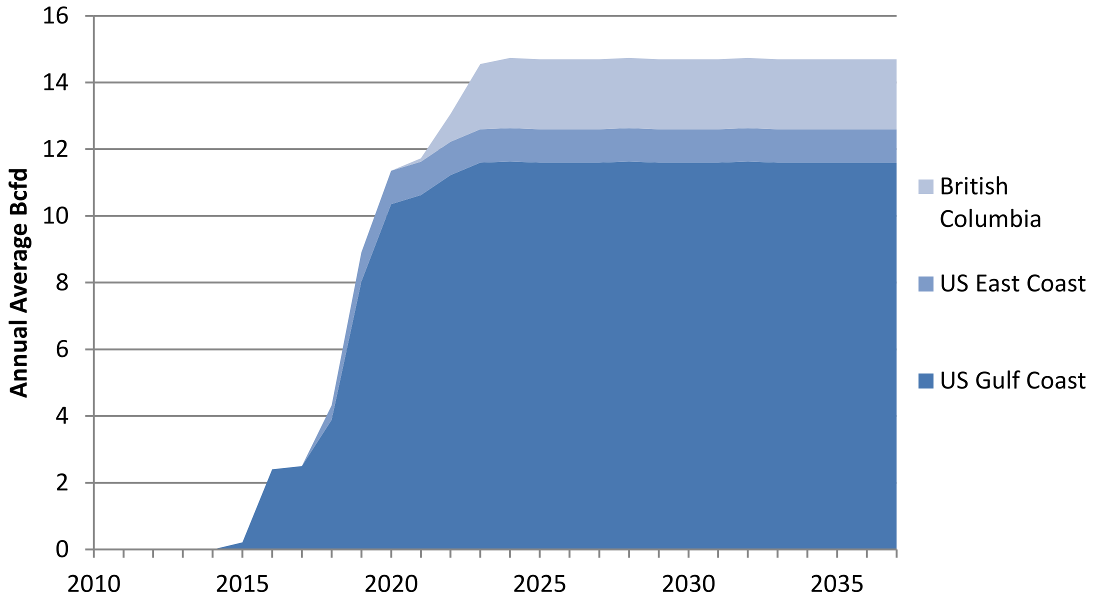
Exhibit 2-3: U.S. and Canada Natural Gas Demand by Sector



*Other includes lease and plant and pipeline fuel use.

Source: ICF GMM® CPP Case, August 2015

Exhibit 2-4: U.S. and Canada LNG Exports

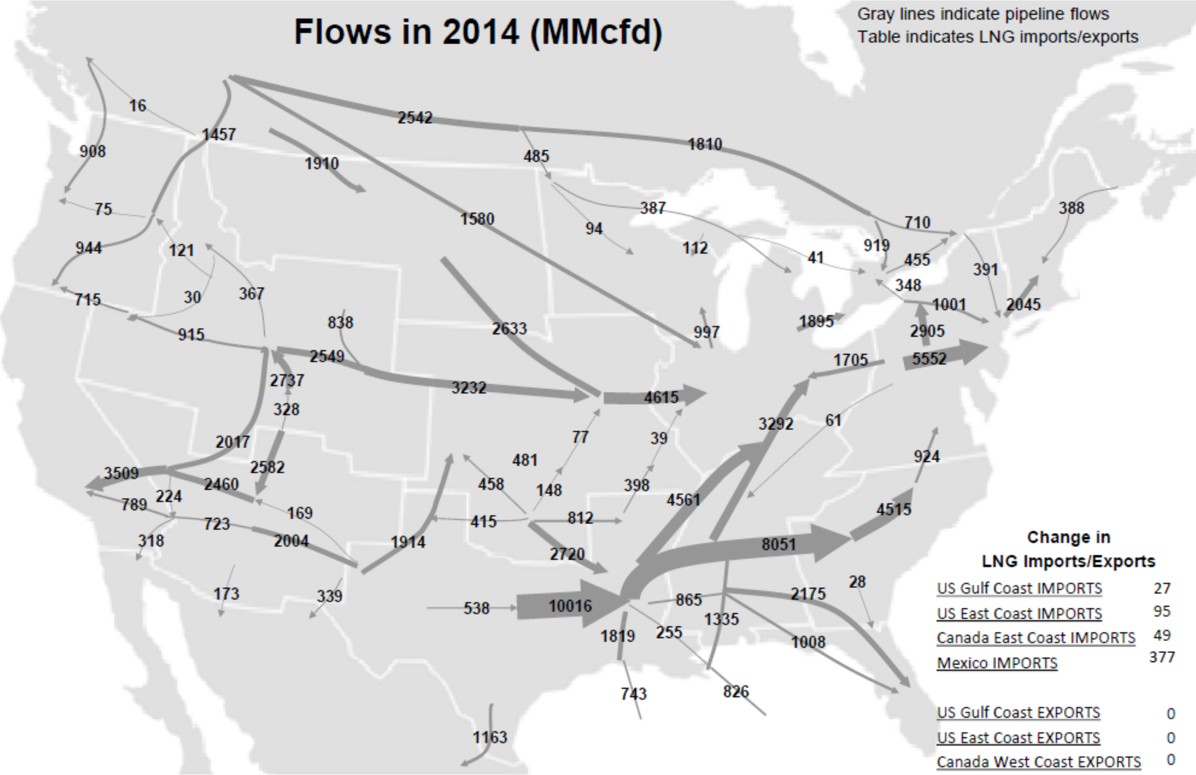


Source: ICF GMM® CPP Case, August 2015

The shifts in regional gas supply and demand have changed interregional pipeline flow patterns, and the changes are likely to continue in the future. Exhibit 2-5 shows the changes in interregional pipeline flows in 2014, and Exhibit 2-6 shows the flows in 2037 in the ICF CPP Case. Both maps show the United States divided into regions and Canada as a single region. The arrows represent gas flows between the regions, and the table in the lower right shows changes in LNG imports and exports.

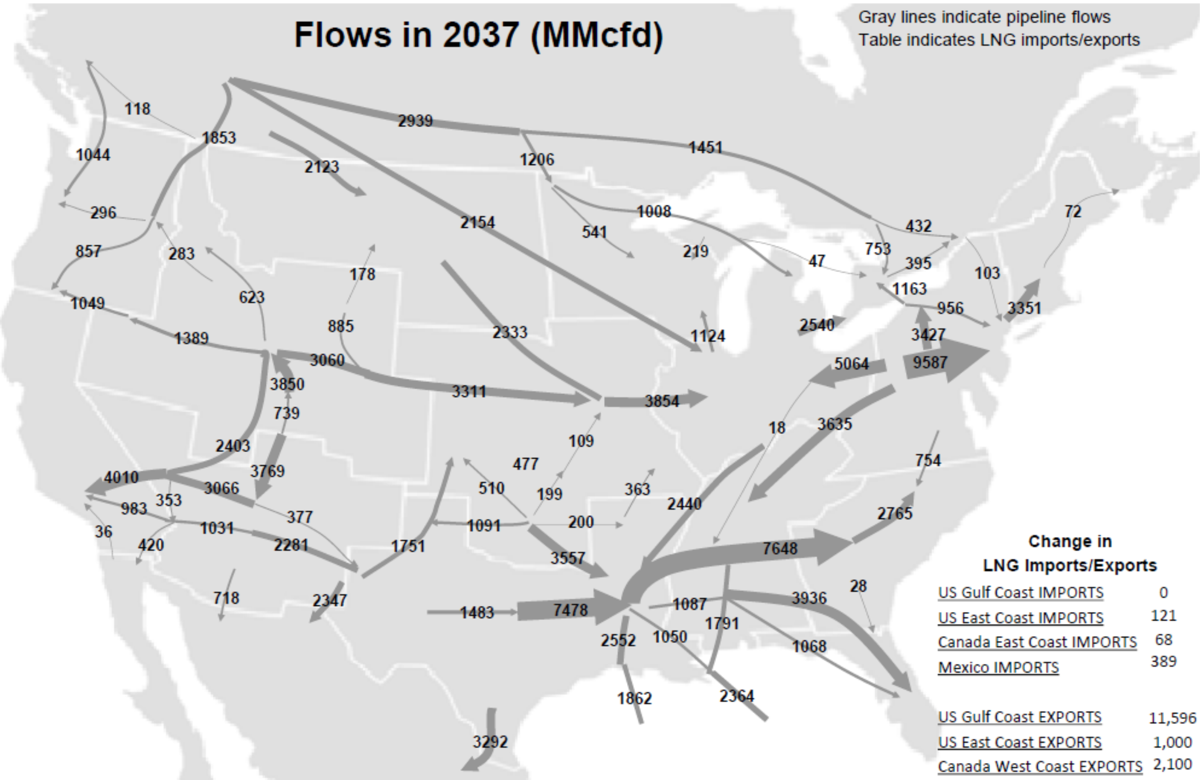
Exhibit 2-5 illustrates how Marcellus/Utica production growth has already changed pipeline flow patterns. Prior to the development of Marcellus and Utica, the Mid-Atlantic and Northeast U.S. relied on gas supplies from the Gulf Coast and Western Canada. As of 2014, the Northeast U.S. was a net exporter of gas, as shown by the flows west and south out of Pennsylvania. Exhibit 2-6 shows the continuation of this trend. As Marcellus/Utica production continues to grow, it becomes a major net exporter of gas, and flows along the traditional in-bound paths are increasingly reversed as gas flows out of the region to the South, to the Midwest, and to Eastern Canada.

Exhibit 2-5: Interregional Pipeline Flows, 2014



Source: ICF GMM® CPP Case, August 2015

Exhibit 2-6: Projected Interregional Pipeline Flows, 2037



Source: ICF GMM® CPP Case, August 2015

Flows from Western Canada to the east remain low, as consumers in Eastern Canada increasingly rely on Marcellus/Utica supplies. Flows out of Western Canada are also limited by increased gas demand within the region to support LNG exports from British Columbia and oil sands development in Alberta.

The changes taking place across North America in natural gas supply and demand will have a fundamental impact on the price relationships between the available sources of natural gas for DTE. Exhibit 2-7 illustrates these impacts.

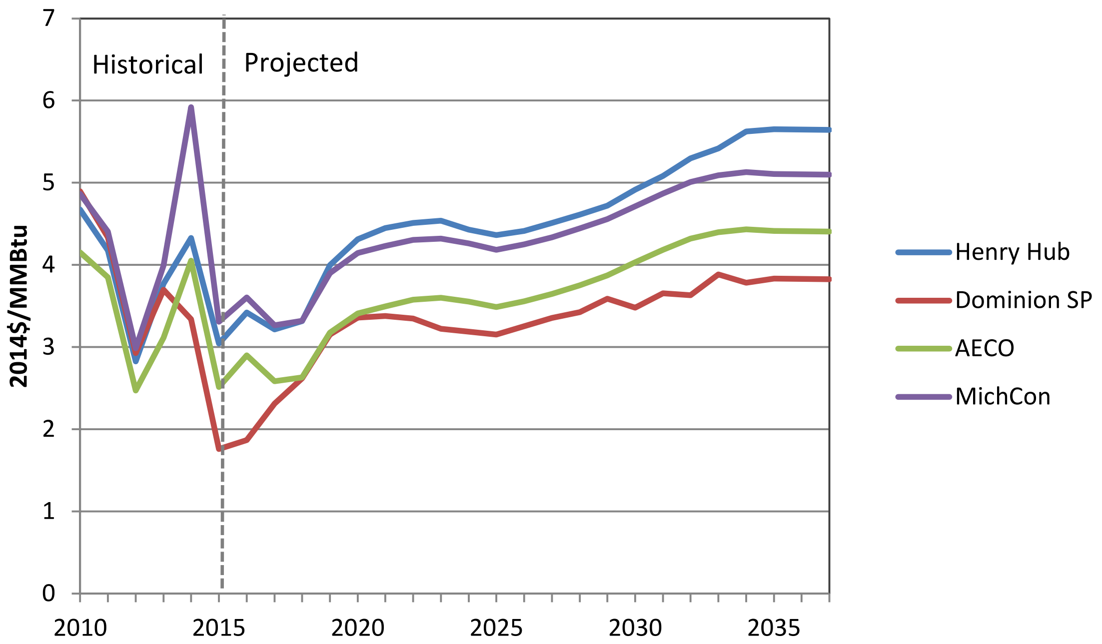
- The rapid growth in Marcellus/Utica supply is turning the Northeastern U.S. into a major supply center, pushing down prices at major Northeast hubs, including Dominion South Point. (Dominion South Point is the most liquid hub in the Marcellus/Utica area, and is used as a proxy for Marcellus/Utica prices.)

- The concentration of demand growth along the Gulf Coast (from LNG exports, Mexican exports, and industrial demand) is changing the Gulf Coast into a net demand region. Prices at Henry Hub are expected to increase relative to Dominion South Point, which attracts gas from Marcellus/Utica to flow southward.

- In Western Canada, the decline in conventional natural gas production, combined with growth in natural gas demand for oil sands production and LNG exports is expected to lead to higher prices at AECO relative to Marcellus/Utica.

These changes in price relationships increase the attractiveness of natural gas supply purchased from Marcellus/Utica for consumers throughout the Northeastern United States, the Midwest and Central Canada, relative to the supply basins that these regions have historically relied upon.

Exhibit 2-7: GMM Average Annual Prices for Selected Markets



Sources:Platts Gas Daily (historical), ICF GMM® CPP Case, August 2015 (projected)

A major determinant of the production outlook for the Marcellus and Utica is the availability of gas pipeline infrastructure to export gas out of the region. In the last three years over 40 distinct projects have been proposed to expand capacity out of the Marcellus/Utica. Exhibit 2-8 summarized the proposed capacity additions out of Marcellus/Utica by their primary destination markets.

Exhibit 2-8: Summary of Proposed Pipeline Expansion Projects from Marcellus/Utica Basin

Destination Market	Proposed Capacity (Bcfd)
Gulf Coast	5.2
Midwest / Ontario	9.6
Northeast	7.5
Mid & South Atlantic	7.0
Western NY / Ontario	4.8

Source: ICF International, compiled from various public announcements.

These projects can be divided into four broad categories:

- Local projects (that is, within Marcellus/Utica) to interconnect pipelines, processing plants, and gathering systems.
- Projects that expand existing pipelines or new pipelines to northeastern markets along from New Jersey to New York and New England. These projects will also tie into pipes interconnecting with Canadian pipes at Niagara, Waddington, and other eastern receipt points.
- Projects that will support reversing the traditional long-haul pipeline flows or adding new pipelines to serve southeastern and Gulf Coast markets.
- Projects that will expand pipeline infrastructure towards Chicago and the Midwest, including reaching Dawn in Canada. The NEXUS Pipeline falls within this group.

As these facilities are constructed and Marcellus and Utica production gains better access to the broader gas market, gas prices in the Marcellus/Utica area would be expected to increase, relative to Henry Hub. Basis spreads between Marcellus/Utica and other markets will better reflect the cost of pipeline transportation than the effects of constraints in takeaway capacity as is now the case. The driving feature behind the NEXUS Pipeline, as well as other pipelines being proposed from this region, is the superabundance of supply seeking markets.

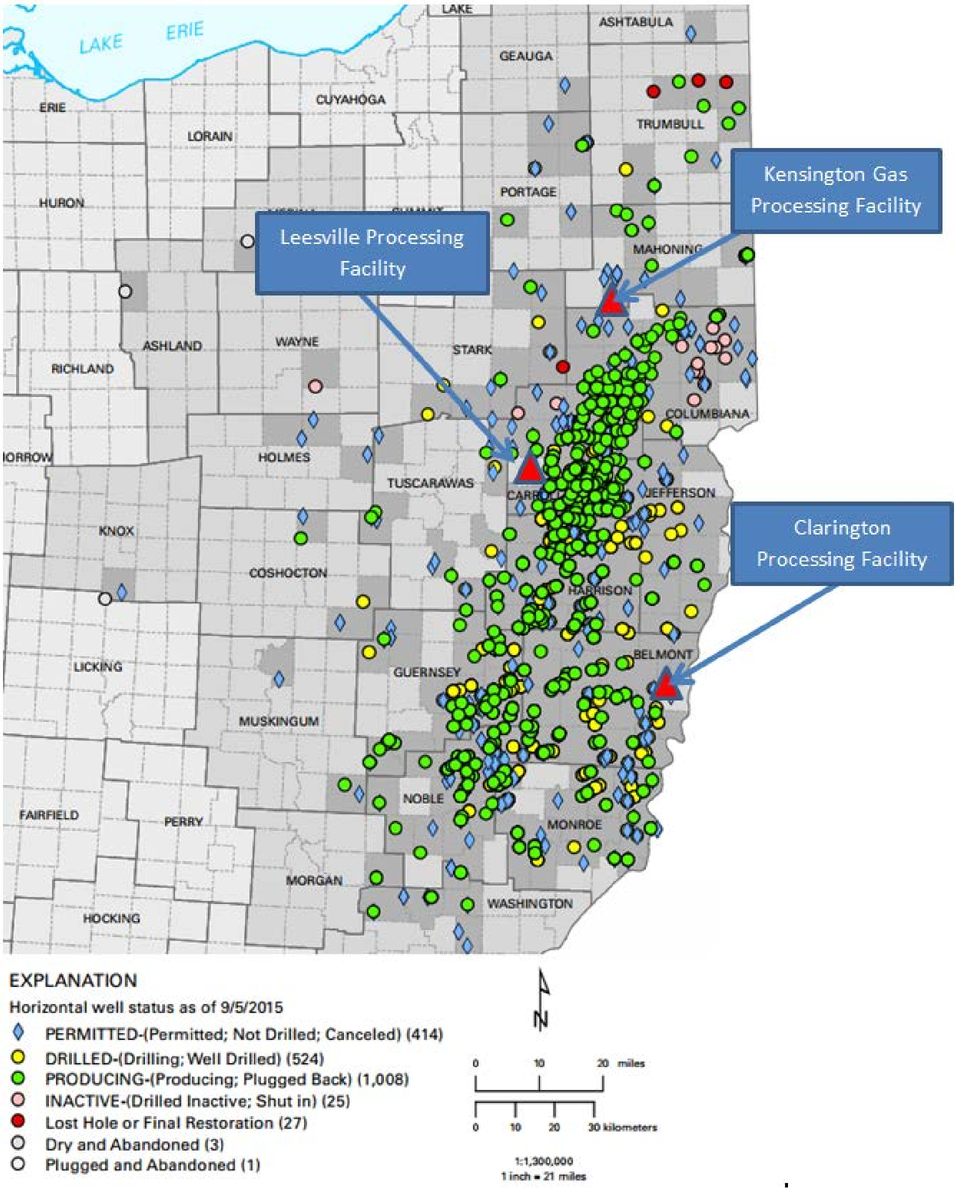
Appendix B provides a more detailed list of the pipeline expansion projects that ICF includes in the Base Case natural gas market forecast.

2.2 Availability of Natural Gas Supply at the NEXUS Receipt Point

The NEXUS Pipeline receipt point at Kensington is located in a prolific producing region in the Utica Shale play. Exhibit 2-9 shows the rig activity in the Ohio Utica Shale area, in close proximity to the proposed NEXUS Pipeline receipt point. Producing Utica wells are shown in green, while permits are shown in blue. Drilled but not yet producing wells are shown in yellow.

When Utica production began to expand rapidly in 2012, the lack of sufficient processing and pipeline capacity in the region initially constrained growth. New pipelines and processing capacity have aided production growth, and additional planned gas infrastructure will help continue this trend. Data published by the Ohio Department of Natural Resources show that over the past year, natural gas production increased from 976 MMcfd (Q2 2014) to 2,438 MMcfd (Q2 2015).[6]

Exhibit 2-9: Ohio Drilling Activity as of September 2015



Source: Ohio Department of Natural Resources

The Kensington gas plant is currently designed to process 800 MMcfd of wet gas produced in this region. The plant is part of the Utica East Ohio Midstream Buckeye (Buckeye) project. The Buckeye project (owned by Access Midstream, M3 Midstream and EV Energy Partners), includes a major gas gathering system ranging from the Kensington facility in the Northeast

[6] Ohio Department of Natural Resources. http://oilandgas.ohiodnr.gov/production accessed September 10, 2015.

down to the Harrison Hub in Harrison County, Ohio and the Leesville Plant in Carroll County, Ohio.

There are currently a number of announced projects in the region to increase gathering and processing capacity, and to interconnect the existing pipelines in the region. The Spectra Ohio Pipeline Energy Network (OPEN) project will add 550,000 Dth per day of pipeline capacity along a 75 mile corridor through the Utica production region from the Tennessee Gas Pipeline near the Kensington plant to the Texas Eastern system in Western Pennsylvania as soon as September 2015.[7] Blue Racer, which is a partnership between Dominion and Caiman Energy is also building out an extensive gathering and processing facility in the region. Additional gathering, processing and pipeline interconnect projects are expected to be announced as production and demand increase.

This region is also well connected with the Marcellus producing regions in Southwest Pennsylvania and Eastern Ohio. NEXUS will include receipt point interconnects with several major interstate pipelines traversing the region, including the Texas Eastern and Tennessee Gas Pipelines. The capacity of the Texas Eastern system in this area is about 2,875 MMcf/d, while the capacity of the Tennessee Gas Pipeline in this area is about 1,025 MMcf/d[8]. Interconnects with Texas Eastern and Tennessee Gas Pipelines increase market liquidity and provide additional security of supply for NEXUS receipts.

The ultimate amount of natural gas produced and processed in this area of the Utica will depend on the amount of pipeline take-away capacity from the region. That is to say, the gas reserves in the region are abundant but underdeveloped. As additional pipeline capacity is constructed to provide access to markets, production from the region will continue to increase. The natural gas gathering and processing facilities needed to fill the pipeline capacity will be developed in conjunction with the pipeline take-away capacity.

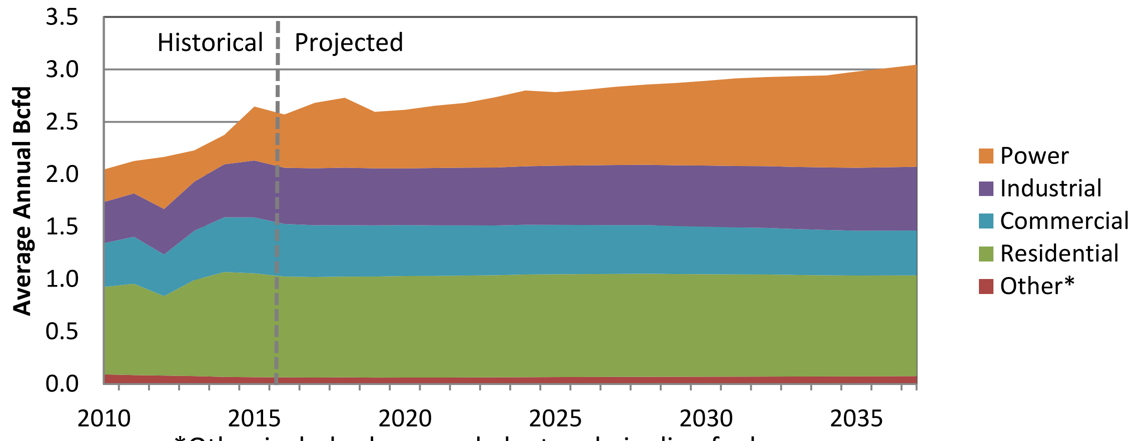
2.3 The Michigan Natural Gas Market

Prior to the 2008/09 recession, Michigan's total gas demand averaged about 900 Bcf per year, or 2.5 Bcfd. While demand declined in all sectors during the recession, the industrial sector was hardest hit, dropping by over 60% from pre-recession levels. Since the recession, gas demand has risen steadily, reaching 2.4 Bcfd in 2014 (Exhibit 2-10). Historically, the power sector has accounted for about 15% of Michigan's total gas demand, averaging about 0.4 Bcfd over the past 5 year.

[7] "OPEN project eyes mid-September startup." Platts Gas Daily, September 10, 2015.

[8] Source: PointLogic Pipeline Database.

Exhibit 2-10: Michigan Natural Gas Demand by Sector

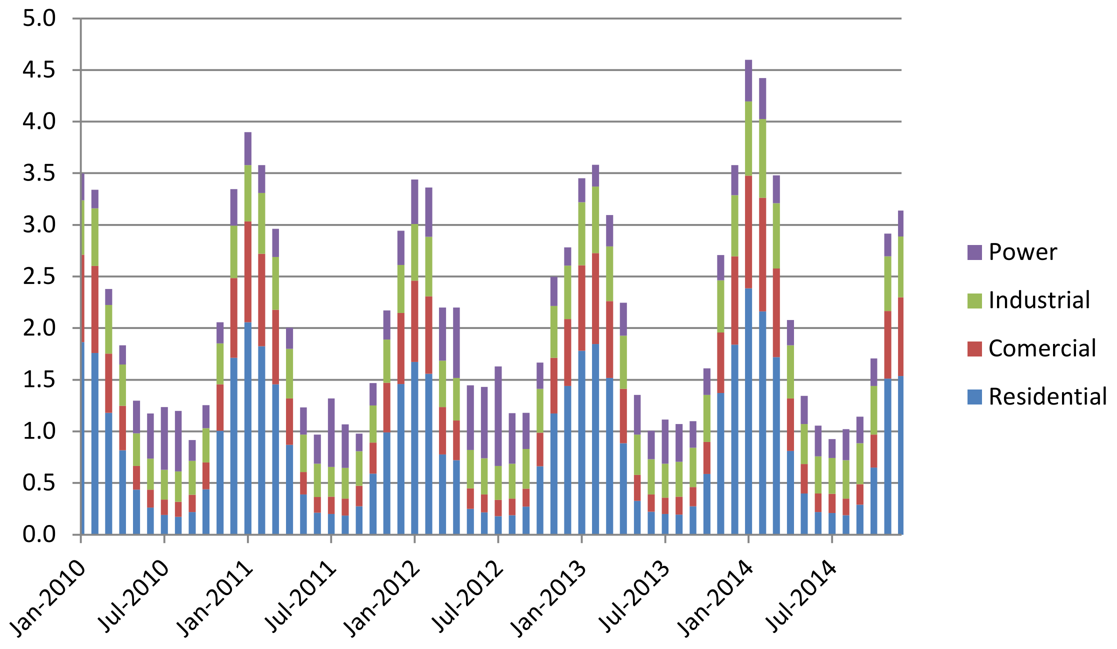


*Other includes lease and plant and pipeline fuel use.

Source: ICF GMM® CPP Case, August 2015

The residential and commercial sectors together account for about 60% of Michigan's total gas consumption. The majority of residential and commercial gas use is for space heating, therefore Michigan gas demand is very seasonal. As shown in Exhibit 2-11, gas demand in the winter months is typically about 2 Bcfd higher than in shoulder and summer months. During the winter of 2013/14, record cold temperatures resulted in a sharp increase in gas demand, with January 2014 averaging 4.6 Bcfd.

Exhibit 2-11: Michigan Historical Monthly Natural Gas Demand by Sector



Source: EIA

ICF projects little change in Michigan's residential, commercial, and industrial sector gas demand over the next 20 years, with combined demand from sectors remaining at about 2 Bcfd. However, gas demand in the power sectors is expected to more than double, reaching 1 Bcfd by 2037. Growth in power sector gas demand is primarily driven by environmental policies (including the CPP), which accelerate the retirement of coal-fired generating capacity. (Factors driving gas demand in the power sector are discussed in greater detail in Section 3.3.2).

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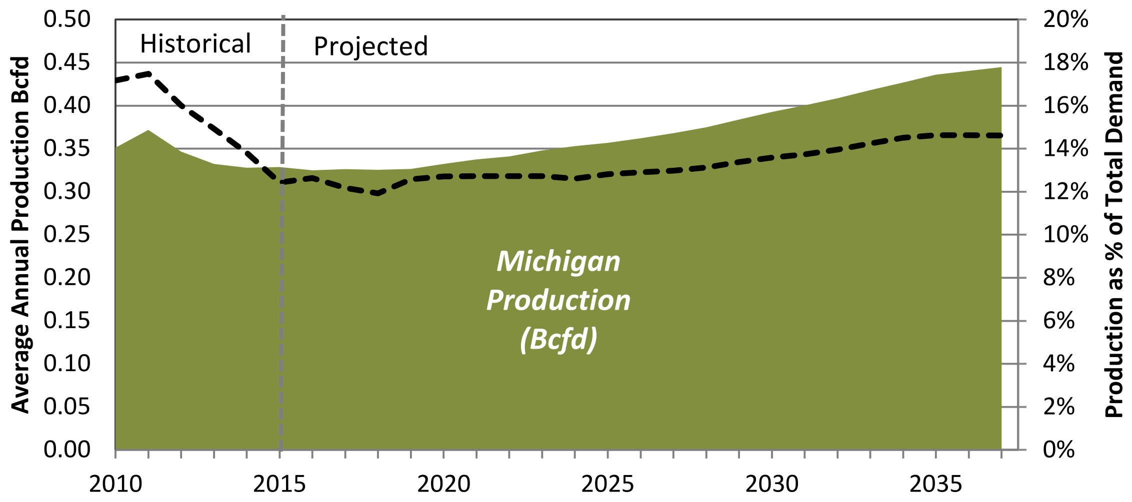
Gas production in Michigan currently accounts for only about 13% of total demand (Exhibit 2-12). ICF projects Michigan gas production will increase modestly through 2037, total gas demand is also increasing (Exhibit 2-12), so the share of total demand met by in-state production continues to average about 13%. The remainder of the state's demand must be met by supplies from other regions delivered via interstate pipelines.

Exhibit 2-12: Michigan Natural Gas Production and Demand

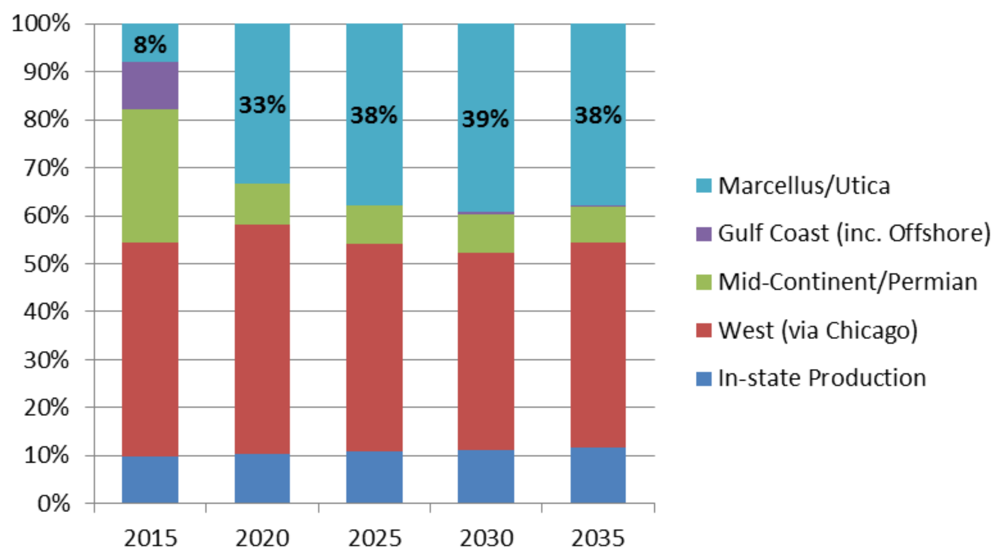


Sources: EIA (historical), ICF GMM® CPP Case, August 2015 (projected)

2.3.1 Changes in Sources of Michigan Natural Gas

The changes in natural gas supply patterns are projected to lead to significant changes in the sources of the natural gas consumed in Michigan. As shown in Exhibit 2-13, even without the NEXUS pipeline, Michigan's reliance on Gulf Coast supplies and Mid-Continent supplies is projected to decline substantially in the next five years, largely replaced by an increase in natural gas sourced from the Marcellus and Utica plays. The shift will be accelerated if the NEXUS Pipeline is developed (Exhibit 2-17).

Exhibit 2-13: Sources of Natural Gas Consumed in Michigan (Without NEXUS)



Sources: ICF GMM® CPP Case, August 2015 (without NEXUS)

2.4 The NEXUS Pipeline

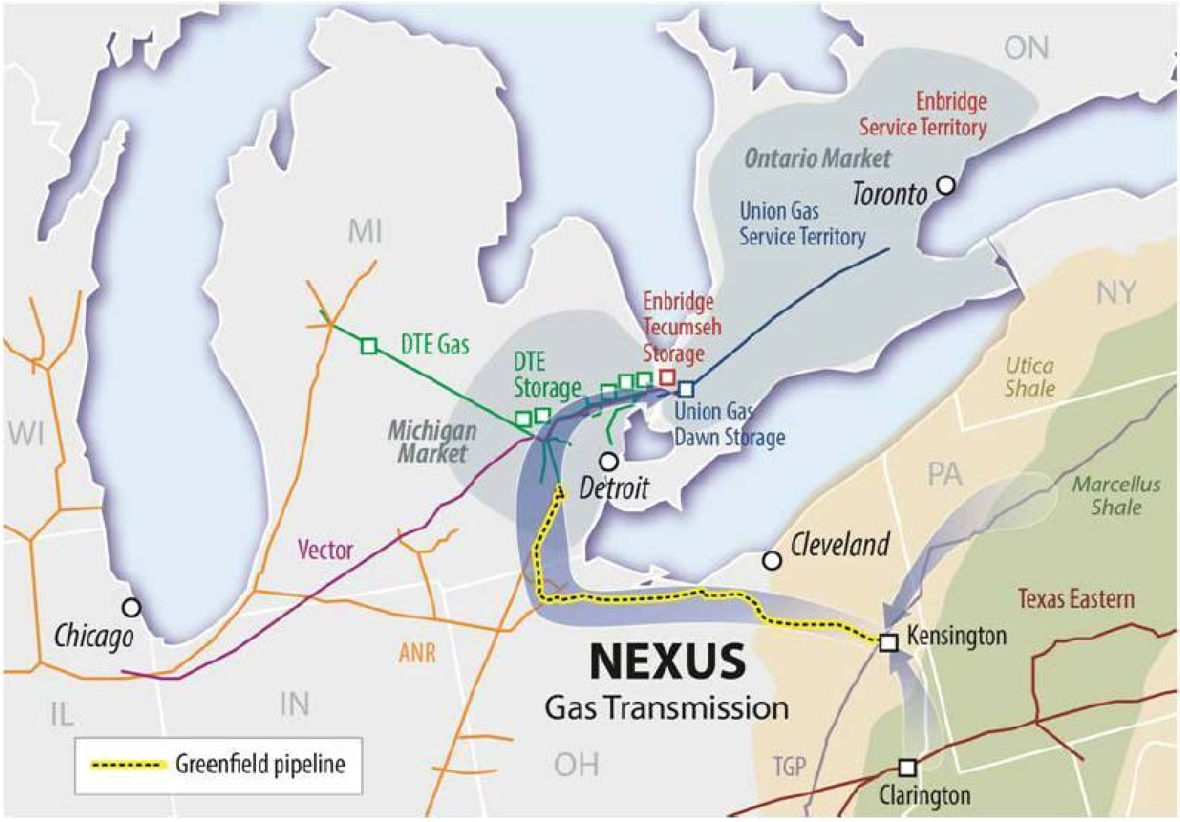
The proposed NEXUS Pipeline would consist of about 250 miles of 36 inch diameter pipe, beginning in eastern Ohio at the Kensington gas processing facility and extend northwesterly to interconnect with the DTE Gas Transmission System and Vector pipeline. The NEXUS Pipeline is jointly owned by Spectra Energy and DTE Energy and is designed to deliver natural gas produced in the Marcellus and Utica plays of the Appalachian Basin directly to gas markets in Michigan and Ontario.

2.4.1 DTE Electric Precedent Agreement for NEXUS Pipeline Capacity

DTE Electric has signed a Precedent Agreement for 30,000 Dth/day of capacity on the NEXUS Pipeline starting November 2017, and increasing to 75,000 Dth/day of capacity after completion of a new combined cycle facility that is expected to be completed in 2022. The agreement term is fifteen years after the increase to 75,000 Dth/day, which is expected to be through 2037.

The agreement between DTE Electric and NEXUS calls for a capacity payment of $21.14 per Dth per month, which equals $0.695 per Dth on a 100% load factor basis, plus fuel use, which has been estimated by NEXUS at 1.9% of throughput.

Exhibit 2-14: Proposed NEXUS Pipeline Route



2.5 Impact of NEXUS Pipeline on Natural Gas Markets

To analyze the impacts of the NEXUS Pipeline on natural gas markets, ICF compared two scenarios using the GMM® with the following assumptions for the Rover and NEXUS expansions:

1) With Rover Pipeline Only (CPP Case August 2015, Rover Pipeline added)
2) With NEXUS and Rover Pipeline (CPP Case August 2015, both Rover and NEXUS capacity added)

ICF also examined the gas market impacts of two additional scenarios where the Rover Pipeline is not completed in order to illustrate the overall impact of additional pipeline capacity from the Marcellus/Utica into Michigan:

1) A "No Pipeline Added Scenario" where both Rover and NEXUS were excluded from forecast pipeline expansions.
2) A "Nexus Only" scenario that includes NEXUS Pipeline capacity but excludes Rover Pipeline.

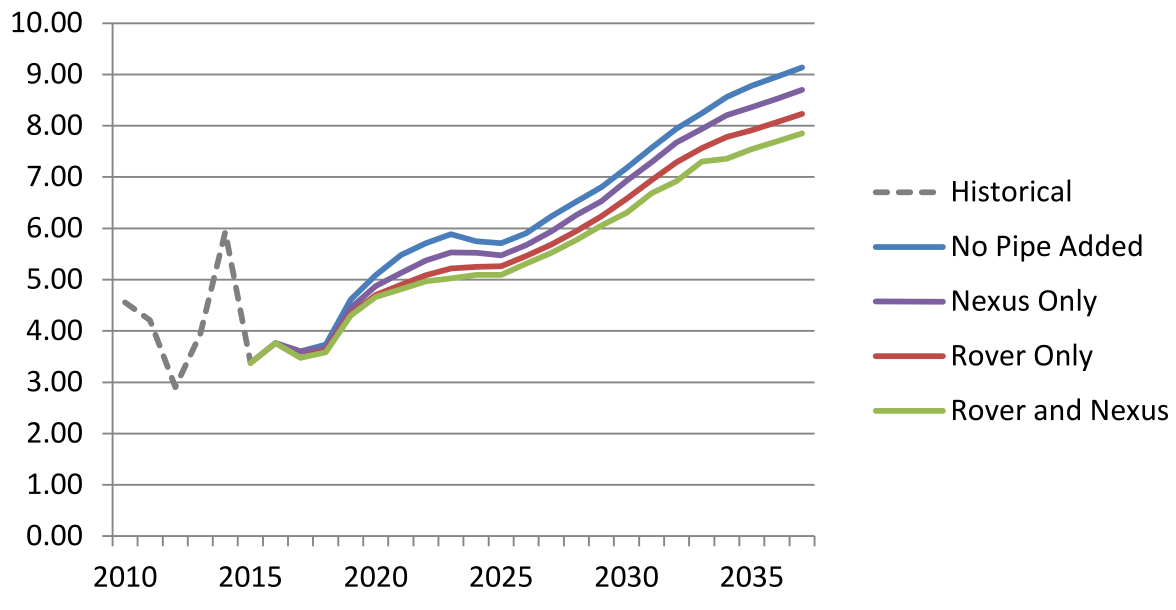
Other than including or excluding the NEXUS and ROVER expansions, all other assumptions were held constant across the scenarios.

ICF's analysis of the NEXUS Pipeline impacts focuses on the two scenarios with Rover Capacity. Since the Rover project's capacity is fully subscribed and the project has been filed with FERC, ICF assumes it is more likely than not that the Rover project will proceed.

2.5.1 Impact of NEXUS Pipeline on Natural Gas Prices

The NEXUS Pipeline has a significant impact on natural gas prices in a range of different North American markets. The projected prices for MichCon (which is representative of gas prices in DTE Electric's service area) with and without incremental pipeline capacity from the Marcellus and Utica supply regions are shown in Exhibit 2-15.

Exhibit 2-15: Impact of NEXUS Natural Gas Prices at MichCon (Average Annual Price in Nominal $/MMBtu)



Sources: ICF GMM® CPP Cases, August 2015 (with and without Rover and NEXUS)

As shown in Exhibit 2-16, projected gas prices at MichCon average $0.21/MMBtu lower with the addition of NEXUS capacity. Development of the NEXUS Pipeline also results in lower natural gas prices in the supply regions that have traditionally supplied the Michigan gas market, including Alberta (AECO), Mid-continent, Chicago, and Lebanon. Gas prices are reduced in these markets due to the addition of incremental gas supplies from Marcellus/Utica, which created additional competition for supplies from these markets.

Exhibit 2-16: Impact of NEXUS on Regional Gas Prices (Average Nominal $/MMBtu, Nov 2017-Dec 2037)

Market Locations	Scenario 1 Rover Only	Scenario 2 Rover and NEXUS	Impact of NEXUS (Scen 2 minus Scen 1)	*Additional Scenarios*	
				No Pipe Added	*NEXUS Only*
MichCon	6.08	5.87	(0.21)	*6.66*	*6.38*
Henry Hub	6.44	6.44	0.01	*6.63*	*6.53*
AECO	5.15	4.96	(0.18)	*5.62*	*5.39*
Mid-continent	5.77	5.62	(0.16)	*6.22*	*6.01*
Chicago	6.01	5.83	(0.19)	*6.55*	*6.29*
Lebanon, OH	5.95	5.79	(0.16)	*6.41*	*6.20*
Defiance, OH	5.97	5.78	(0.19)	*6.60*	*6.32*
Dominion South Point	4.63	4.83	0.20	*4.09*	*4.32*
Kensington (NEXUS Receipt Point)	4.75	4.95	0.20	*4.21*	*4.44*

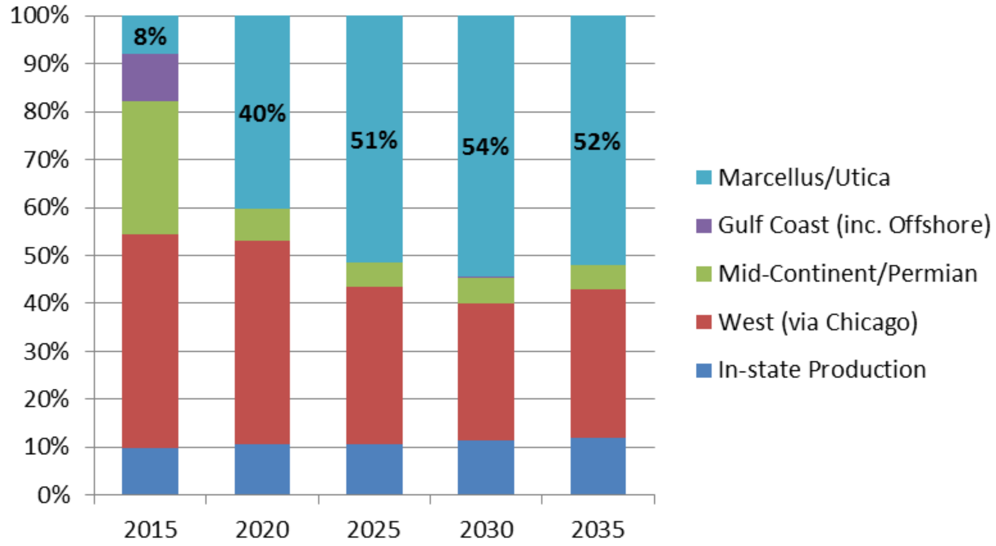
Sources: ICF GMM® CPP Cases, August 2015 (with and without Rover and NEXUS)

In contrast, the availability of new pipeline capacity out of Marcellus/Utica reduced constraints on outbound capacity from this region; therefore, prices at both Dominion South Point and Kensington (the NEXUS receipt point) are higher with the NEXUS Pipeline. However, even though gas prices at Kensington increase with the addition of NEXUS capacity, it remains a low cost gas supply hub for Michigan natural gas consumers.

2.5.2 Increased Access to Marcellus/Utica Production

The development of the NEXUS Pipeline also results in a significant increase the amount of Marcellus/Utica natural gas supply consumed in Michigan. As shown in Exhibit 2-17 (supply sources with NEXUS Pipeline) compared to Exhibit 2-13 (supply sources without NEXUS Pipeline), the addition of the NEXUS Pipeline increases Marcellus/Utica share of Michigan's total gas supply by about 14%. The increase in Marcellus/Utica supplies to Michigan displaces gas supplies from other higher cost areas, thereby reducing the cost of gas to Michigan consumers.

Exhibit 2-17: Sources of Natural Gas Consumed in Michigan (With NEXUS)



Sources: ICF GMM® CPP Cases, August 2015 (with NEXUS)

2.5.3 NEXUS Pipeline Receipt Point Prices

The NEXUS Pipeline will establish a new natural gas pricing dynamic around the pipeline receipt and delivery point(s) once the pipeline is in place. In addition, the pipeline will provide market access for natural gas supplies from the rapidly growing Utica Shale play. Since Utica Shale development is still relatively new, there is currently no direct market proxy for pricing NEXUS Pipeline receipts. For its analysis of projected NEXUS receipt point prices, ICF uses the Dominion South Point price. Dominion South Point is the largest and most liquid market center in the region, and includes segments of the Dominion system in close proximity to the Kensington gas plant.

Platt's determines the Dominion South Point index price based on reported transactions within the region defined as:

> "Deliveries into two Dominion Transmission main lines: One runs northeast from Warren County, Ohio, midway between Cincinnati and Dayton, and merges with the second line just northeast of Pittsburgh, Pa. The second line runs from Buchanan County, Va., on the Virginia/West Virginia border north to the end of the zone at Valley Gate in Armstrong County, Pa."

Natural gas production in the immediate region of the NEXUS receipt point is expected to continue to increase; however, we expect the price of gas in the region around the NEXUS delivery point to continue to sell at a premium over the Dominion South Point price. The price premium is estimated to be between $0.12 to $0.14 per Dth, representing $0.10 per Dth in transportation, plus 0.5% fuel and other variable costs associated with delivering gas into the NEXUS Pipeline.

2.5.4 Access to Marcellus/Utica Production Area Prices

Holding NEXUS capacity provides the ability to purchase natural gas at prices in the Marcellus and Utica supply basins. While NEXUS provides a direct link from the Marcellus and Utica into Michigan, the majority of the value of holding NEXUS capacity is on the section of the pipeline from the Marcellus and Utica basins into Central and Western Ohio.

ICF's projection of natural gas prices indicates that of the $0.92/MMBtu of total price difference (also referred to as "basis spread") between Kensington and the MichCon Citygate, $0.83/MMBtu (90% of the total difference) occurs between Kensington gas market centers at Defiance in Northwest Ohio (see Exhibit 2-16 above). Because lower gas prices are located closer to the source in Marcellus/Utica, holding capacity on a pipeline that reaches all the way back to supplies at Kensington provides greater benefit to DTE Electric than holding capacity to Defiance alone.

2.5.5 DTE Electric Utilization of NEXUS Pipeline Capacity

Based on information provided to ICF by DTE Electric, DTE Electric does not expect to fully utilize the capacity contracted on the NEXUS Pipeline during the first few years of the contract (through 2021). Capacity utilization will increase to approximately 40% after the first new combined cycle plant is brought into service, and the NEXUS Pipeline capacity is expected to be fully utilized once a second combined cycle unit is brought online. Until the second combined cycle facility is brought on-line, DTE Electric will not be using all of the available NEXUS Pipeline capacity to meet DTE Electric natural gas load requirements.

Instead, DTE Electric plans to release available capacity to the market in order to recover the value of the unutilized pipeline capacity. Given the size and liquidity of the MichCon Citygate market, ICF has valued the available capacity at the basis differential between Kensington and the MichCon Citygate (see Exhibit 2-16 above).

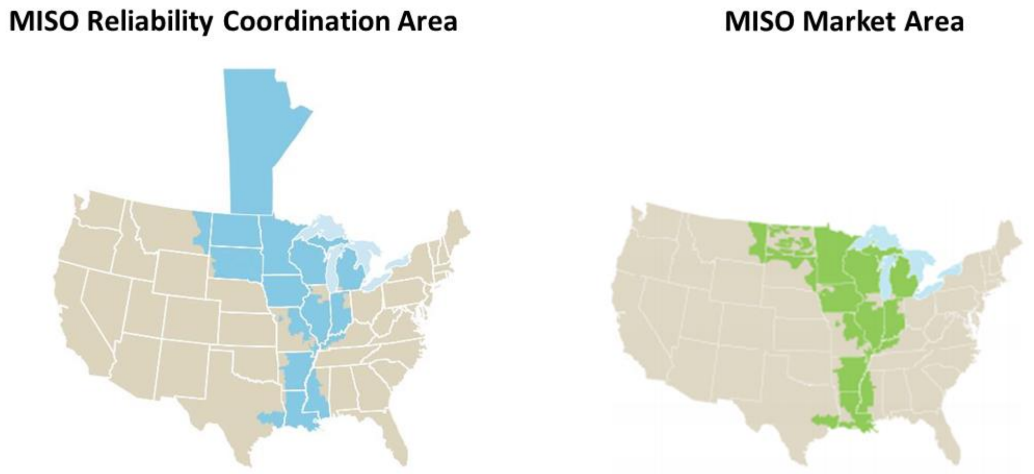
3 Midwest Power Markets

Section 3 provides an overview of Midcontinent Independent System Operator (MISO) market area with focus on the lower Michigan peninsula. Further Section 3 highlights the modeling approach and provides a summary of the key market assumptions influencing future power prices in this market. Finally, Section 3 presents the impact to the wholesale energy and capacity markets expected from the addition of the NEXUS Pipeline,

3.1 Overview of the Midcontinent Independent System Operator (MISO) Area

The Midcontinent Independent System Operator, Inc. (MISO) is a not-for-profit, member-based Regional Transmission Organization (RTO) administering wholesale electricity markets. MISO operates the transmission system and a centrally dispatched market in portions of 15 states in the Midwest and the South, extending from Michigan and Indiana to Montana and from the Canadian border to the southern extremes of Louisiana and Mississippi. MISO has responsibility as a reliability coordinator for all its utility members and as manager of an energy market for a slightly smaller geography; MISO also serves as the Balancing Authority for the market area (see Exhibit 3-1).

Exhibit 3-1: MISO Reliability Coordination and Dispatch Control Areas



Source: MISO, Corporate Information, March 2015

MISO Primary Roles for its stakeholders include:

- Provide independent transmission system access
- Deliver improved reliability coordination
- Perform efficient market operations
- Coordinate regional planning
- Foster platform for wholesale energy markets

Prior to beginning operations in December 2001, MISO was not a power pool, unlike areas like PJM, New York and New England. MISO began its market operations in April 2005. In January 2009, MISO started operating an ancillary services market and combined its 24 separate balancing areas into a single balancing area. In 2013, the RTO began operations in the MISO South region, including the utility footprints of Entergy, Cleco, and South Mississippi Electric Power Association, among others, in parts of Arkansas, Mississippi, Louisiana, and Texas.

As a Balancing Authority, MISO is the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation-balance within a Balancing Authority Area and supports interconnection Frequency in real-time. This energy balance takes into account the Interchange of power between MISO and other neighboring RTOs, such as PJM. Within the MISO footprint, there are sub-regions referred to as control areas or local balancing authority areas.

Within MISO, Local Balancing Authorities (LBAs) monitor the system and relay dispatch instructions during normal operations. LBAs have full responsibility for supply and demand balancing during islanded situations and system restoration. Currently, the MISO footprint is made up of 36 individual LBAs that work with the MISO Balancing Authority. Each of these LBAs must meet and comply with NERC standards, just as MISO does. The Michigan Electric Coordinating Council (MECs) is one of the LBAs which spans the lower Michigan peninsular area and is the focus of this study.

There are 363 operating protocols. Both the MISO Balancing Authority and the LBAs will share responsibilities for 243 of them. The MISO Balancing Authority will be solely responsible for 136 of the protocols while the LBAs will be solely responsible for six operating protocols. This division of responsibility of operating protocols is a result of the Balancing Authority Alignment Agreement. An overview of MISO is provided in Exhibit 3-2.

Exhibit 3-2: MISO Operating Statistics

Metric	Parameter
Territory	Covers portions of 15 states for reliability coordination (plus one province) and market area; control centers in Carmel, IN, St. Paul, MN, and Little Rock, AR.
Market Participants	413 market participants including 50 Transmission Owners with $31.4 billion in transmission assets under MISO's functional control and 123 non-transmission owners
Generation Capacity	179,514 MW (market); 201,964 MW (reliability)
Historic Peak Load (set January 6, 2014)	109,307 MW (market); 117,629 MW (reliability)
Transmission	65,800 miles of transmission within Reliability Coordination Area
Market Operations	Uses security-constrained economic dispatch of generation; operates a Day-Ahead Market, a Real-Time Market, a Financial Transmission Rights (FTR) Market, and an Ancillary Services Market (ASM)
Balancing Authorities	36 Local Balancing Authorities (LBAs) in the MISO Reliability Coordination Area

Source: MISO, Corporate Information, March 2015

3.1.1 Entergy Integration into MISO

On December 19, 2013, six local balancing authorities, 10 new transmission owning companies, and 33 new market participants from Mississippi, Louisiana, Arkansas, Texas, and Missouri joined MISO. Commonly known as the Entergy integration, this joining activity created a Southern Region in MISO (MISO South).

MISO South includes the following transmission owners and local balancing authorities:

- Entergy (Arkansas, Mississippi, Louisiana, Texas, Gulf States, and New Orleans)
- Cleco Corporation
- Lafayette Utilities System
- Louisiana Energy and Power Authority
- Louisiana Generating
- South Mississippi Electric Power Association
- East Texas Electric Cooperative

Prior to the recent MISO South integration, there were four trading hubs: MISO-Indiana, MISO-Illinois, MISO-Michigan, and MISO-Minnesota. Three additional MISO South hubs have been active since December 2013: the Arkansas, Louisiana, and Texas hubs.

The integration also effectively defined certain zonal definitions within MISO and opened up greater opportunity for resource sharing to the traditional MISO area.

3.1.2 Capacity and Generation Mix

A substantial share of capacity in MISO remains coal-fired. However, due to the integration of MISO South, coal-fired generation retirements, and gas-fired generation expansion, gas-fired resources have increased in total share and importance in MISO. After the integration of MISO South in December 2013, the share of MISO's capacity that is gas-fired increased to 39 percent from 30 percent, and reduced the share that is coal-fired to 46 percent from 57 percent as illustrated in Exhibit 3-3.

Exhibit 3-3: Capacity, Energy Output and Price-Setting by Fuel Type, 2013-2014

	Installed Capacity (Summer)				Energy Output		Price Setting			
	Total (MW)		Share (%)		Share (%)		SMP [1](%)		LMP [1](%)	
	2013	2014	2013	2014	2013	2014	2013	2014	2013	2014
Nuclear	7,299	12,763	7%	9%	12%	16%	0%	0%	0%	0%
Coal	61,234	66,658	57%	46%	71%	58%	82%	75%	90%	90%
Natural Gas	32,415	55,852	30%	39%	8%	17%	17%	23%	30%	84%
Oil	2,391	3,125	2%	2%	0%	0%	0%	0%	2%	4%
Hydro	2,165	3,621	2%	3%	1%	1%	0%	0%	2%	2%
Wind	1,600	1027 [2]	1%	1%	8%	6%	0%	1%	50%	58%
Other	610	564	1%	0%	0%	1%	0%	0%	2%	4%
Total	**107,714**	**143,610**								

Source: 2014 STATE OF THE MARKET REPORT FOR THE MISO ELECTRICITY MARKETS, Potomac Economics, June 2015.
Notes:
1. SMP stands for System Marginal Price and LMP stands for Locational Marginal Price.
2. The capacity values in table are consistent with MISO's planning values, so they are derated from the nameplate capacity level. Wind capacity value in 2014 are lower than in 2013 because they are calculated

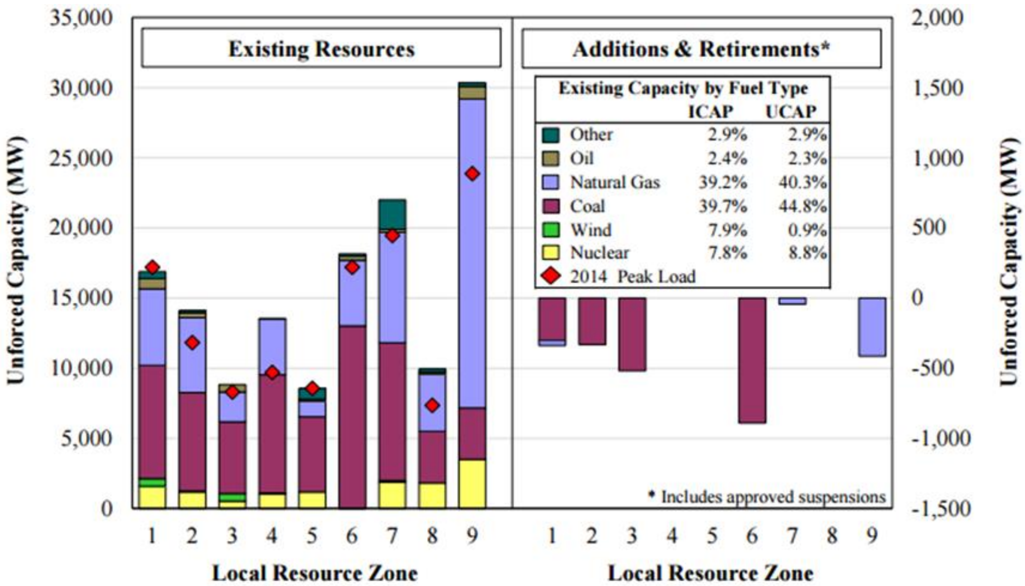
relative to all installed resources, which expanded with the MISO South integration, and there is no wind capacity in the South region.

The low-cost resources (coal and nuclear) produced most of the energy while natural gas-fired units produced 17 percent of MISO's energy in 2014. This was more than double the share produced in 2013, but lower than the share of capacity that is gas-fired. However, while the total output share is modest, the time prices are established by gas-fired generation as the marginal unit is significant. Natural gas-fired units set the system-wide price in 46 percent of all intervals from January to March 2014 and in 23 percent all intervals for all of 2014. Congestion frequently causes natural gas-fired resources to be on the margin in a local area in the same interval that a lower-cost resource may be setting the system-wide price. Hence, natural gas set LMPs in local areas in 84 percent of all intervals, which underscores why natural gas prices continue to be an important driver of energy prices. This is particularly significant in the Michigan market relevant to the decrease in gas prices, driven by the addition of NEXUS as will be shown in the results.

3.1.3 Supply and Demand Balance

As seen in Exhibit 3-4 below, the capacity resources (unforced capacity credit available in the capacity market) expected to be available in the MISO market for summer 2015 remained dominantly coal-fired in the northern markets while MISO South (Zone 9) maintains significantly more gas generation.

Exhibit 3-4: MISO Distribution of Generating Capacity, Summer 2015 Projected

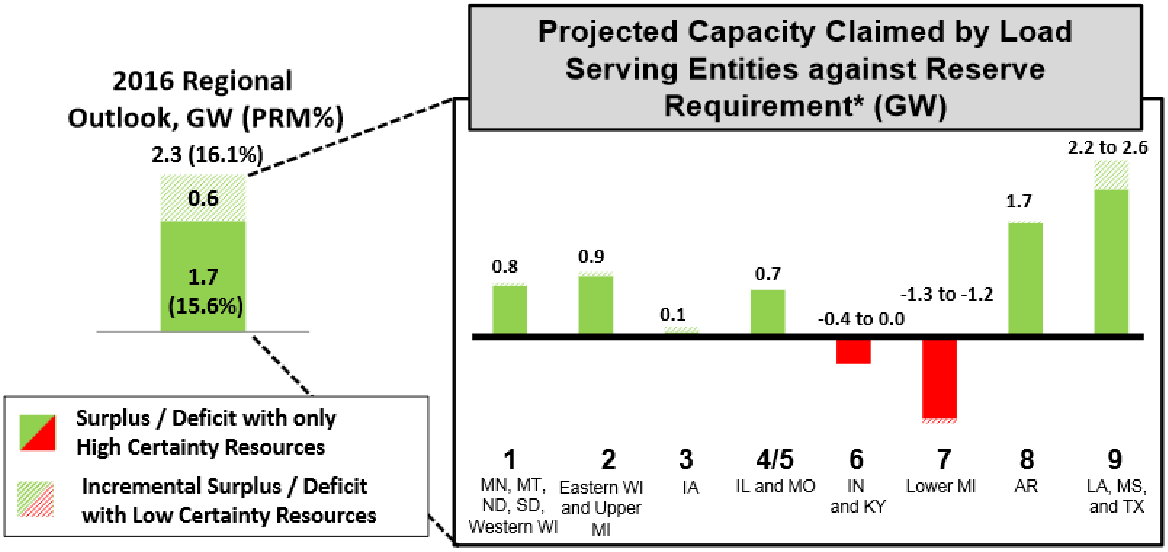


Source: 2014 STATE OF THE MARKET REPORT FOR THE MISO ELECTRICITY MARKETS, Potomac Economics, June 2015.

Going forward, MISO has considered the impact of up to eight GW of coal retirements through the summer of 2016. This trend of coal retirements combined with higher capacity exports to PJM, may substantially reduce MISO's planning reserve margins.

In 2014, MISO indicated an anticipated shortage in 2016 of 2.3 GW overall, with a concentration in Michigan with an anticipated shortage of 3 GW. Recently, in April 2015, MISO has reduced expectations for load and increased expectations for committed resources in 2016, thereby resulting in revised adequacy projections for 2016 of a surplus supply of 1.7 to 2.3 GW with 1.2-1.3 GW shortage in lower Michigan (known as MISO Zone 7) as seen in Exhibit 3-5.

Exhibit 3-5: Regional Capacity Surplus and Deficit in MISO



Source: 2015 OMS MISO Survey Results, July 2015.
https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/SAWG/2015/20150709/20150709%20SAWG%20Item%2002%202015%20OMS-MISO%20Survey%20Results.pdf

The 2016 projections account for expected retirements and capacity sales to PJM. The projected shortage for Michigan's Lower Peninsula (Zone 7) does not reflect lack of physical generation capacity within the zone, but rather that some generators located in the state can choose to supply capacity into the neighboring PJM Interconnection. The capacity sales to PJM reflect commitments for a longer term period (three years) than visible in the MISO capacity markets which are transacted on a forward year basis only.

Going forward, it is anticipated environmental regulations will continue to impact the capacity available in MISO and Michigan. MISO's recent capacity survey found 15.7 GW of coal capacity may be affected by multiple federal rules in the next five years. Retiring coal and other capacity could force reserve margins below required levels in Iowa, Indiana, Kentucky, Minnesota and Michigan, so that grid-wide resource adequacy margin could range from a 0.5GW surplus to a 2.3GW deficit. The survey did not explicitly consider the implications of the US Environmental Protection Agency's (EPA's) Clean Power Plan (CPP), which was released in its final form in August 2015.

Countering the impact of retirements could be the addition of new facilities to the MISO market area. Unlike the PJM capacity market, MISO's capacity market focuses on the prompt year only and bids are not subject to a Minimum Offer Price Rule (MOPR). With the dominance of utilities (and their preference for self-supply), lack of MOPR rules, and a vertical demand curve; MISO capacity markets have not been supportive of merchant generators. To encourage greater competition, transparency, and merchant plant development, a group of capacity suppliers recently submitted a motion seeking expedited action in the capacity markets including the following elements:

- An order requiring a mandatory capacity market for buyers and sellers
- A MOPR
- The elimination of the ability to opt-out under self-supply (fixed resource adequacy plans)
- The establishment of a three-year planning commitment with a downward sloping demand curve

3.1.4 *Transmission Infrastructure*

MISO has interconnections with the PJM and Southwest Power Pool (SPP) RTOs. It is also directly connected to Southern Co., TVA, the Western Area Power Administration, the electric systems of Manitoba and Ontario, in addition to several smaller systems. Overall, MISO is a net importer of power, however, the interchange with some areas can flow in either direction, depending on the relative loads and prices in the adjoining regions. Manitoba Hydro supplies a large part of MISO's load with its excess capacity, particularly in the summer. The PJM interface is MISO's largest and most actively scheduled interface. MISO has been a net importer from PJM.

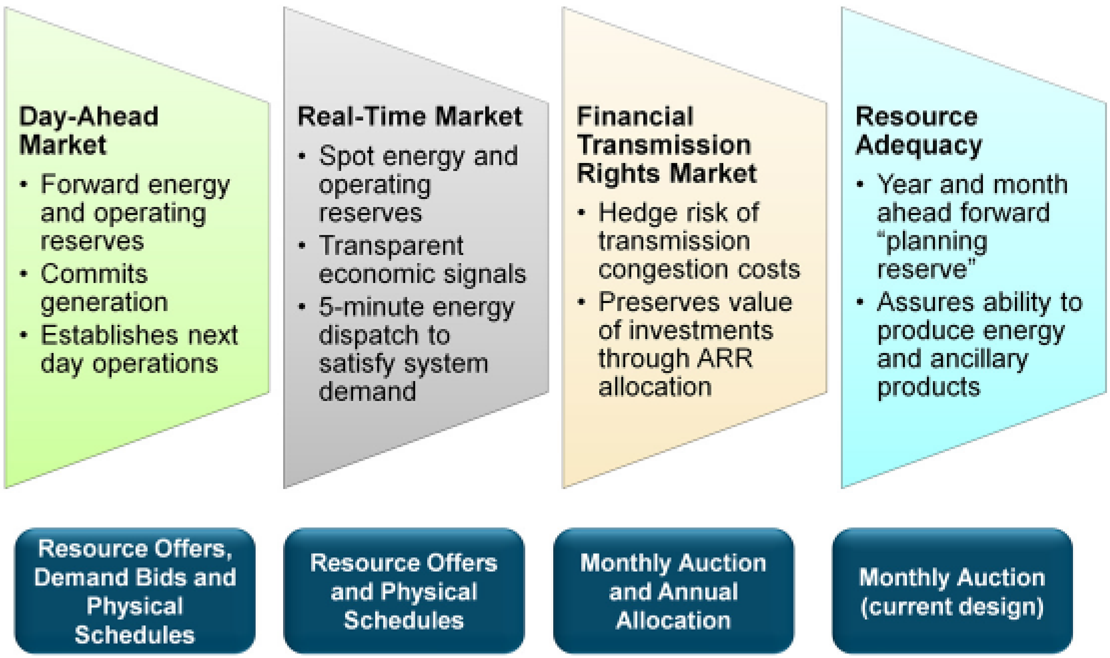
MISO has certain pathways that are more likely to become congested. However, the likelihood and pattern of congestion in any area is subject to factors like weather patterns, wind production and interchange with external regions. When load is high in the eastern part of MISO and to the east in PJM, constraints occur on pathways from the Minnesota and Wisconsin areas through Chicago and across Indiana. A particular congestion point with this pattern is Northern Indiana. When cold weather hits Minnesota and the Dakotas, there is often congestion in the northern direction, particularly in Iowa. Higher wind production can cause localized constraints in some areas and congestion in pathways from Southern Minnesota and Western Iowa moving eastward. New Orleans and east Texas are also two constrained areas in MISO South. Additionally, constraints arise between Missouri and Arkansas, which connects the MISO Midwest with MISO South.

3.2 MISO Market Structure

3.2.1 *MISO Markets Overview*

There are four primary markets for stakeholders to participate in with MISO as illustrated in Exhibit 3-6.

Exhibit 3-6: MISO Market Structure



The following markets serve as MISO's primary tools to efficiently manage generation and transmission assets in the footprint.

1) Day Ahead:
- Forward Market for energy and operating reserves – offered and cleared simultaneously.
- Pricing by physical location (CPNode)
- Facilitate an efficient commitment of generation
- Establishes next day plan of operations
- Participation in this market includes: Generation resource offers, load demand bids, physical schedules and some bilateral transactions

2) Real-Time:
- Spot energy and operating reserves – offered and cleared simultaneously.
- Pricing by physical location (CPNode)
- Dispatch the lowest-cost resources to satisfy system demand without overloading the transmission network
- Provide transparent economic signals to guide short-run operational and long-run investment decisions by participants and regulators
- Participation in this market includes: Updated generation resource offers, updated load forecasts

3) Financial Transmission Rights (FTRs)
- Allows participants to hedge transmission congestion costs risk from serving load or other market transactions
- Preserves the value of existing investments through annual Auction Revenue Rights (ARRs) allocation
- Participation in this market includes: Nominating and participating in the annual ARR allocation, bidding in the monthly FTR auction and bilateral transactions

4) Resource Adequacy
- Year and month ahead forward "planning reserve" or "capacity" product
- Assures ability to produce energy and ancillary products
- Participation in this market includes the monthly voluntary capacity auction.

This analysis focuses on the Day-Ahead and Resource Adequacy markets.

3.2.2 MISO Energy Market

3.2.2.1 Overview

On April 1, 2005, MISO began operating a market-based, congestion management system including a Day-Ahead and Real-Time energy market, and a FTRs market.

The day-ahead market enables market participants to buy or sell energy, schedule transactions, or hedge congestion costs at financially binding locational marginal prices (LMPs). The day-ahead market allows market participants to secure prices for electric energy the day before the operating day and hedge against price fluctuations that can occur in real time.

The real-time market is utilized to meet the instantaneous demand for electricity, which has changed from the day-ahead expectations. Supply or demand for the operating day can change for a variety of reasons, including unforeseen generator or transmission outages, transmission constraints or changes from the expected demand. The real-time energy market is operated to meet actual energy needs within each hour of the operating day. Real-time transactions are priced using the LMP system.

Real-time market is prepared for at the conclusion of the day-ahead market on the day before the operating day. MISO clears the real-time market using supply offers, real-time load and external offers. For generators, additional opportunities to offer supply are provided by the market to help meet incremental needs. Load serving entities (LSEs) whose actual demand comes in higher than what was scheduled in the day-ahead market may secure additional energy from the real-time market. Majority of the volume transactions occur in the day-ahead markets.

The real-time market financially settles the differences between the day-ahead scheduled amounts of generation. LMP values have three components for settlement purposes: marginal energy component, marginal congestion component, and marginal loss component.

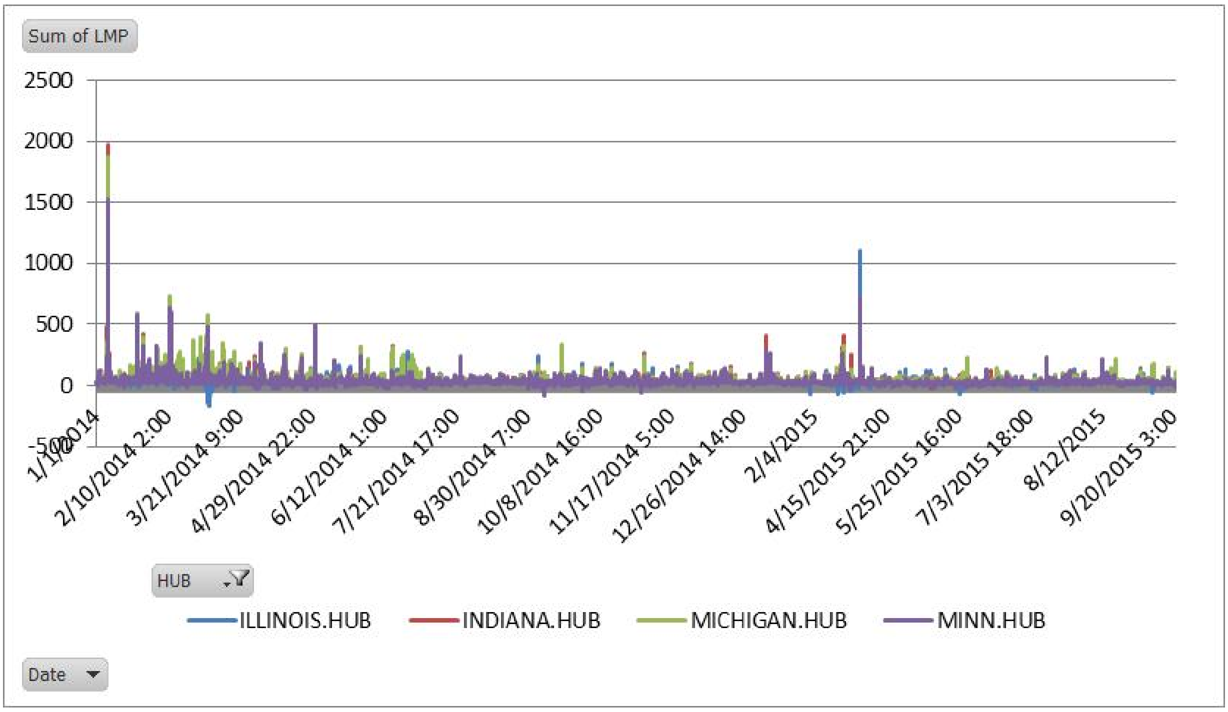
The ICF forecasts presented herein are reflective of day-ahead market transactions.

3.2.2.2 Historical Prices

MISO has seven trading hubs including four hubs in the Midwest and three hubs in the South. The Texas Trading Hub, Arkansas Trading Hub and Louisiana Trading form the hubs in the South while Illinois, Indiana (formerly Cinergy, Minnesota, and Michigan reflect MISO's Midwest trading hubs. The trading hubs create common points for commercial energy trading in order to foster more liquid trading activity and efficient commercial transactions between all market participants.

Within the Midwest, the Michigan price has on average been the higher priced of the four Midwest hubs averaging $36.9/MWh since January 2014 versus $34.8/MWh at the Indiana Hub, $31.8/MWh at the Illinois Hub, and $28.8 at the Minnesota Hub. In part, this higher pricing is reflective of higher delivered fuel costs to the Michigan area. Hourly prices at the four Midwest Hubs since January 2014 are illustrated in Exhibit 3-7, though Michigan tends to clear at a higher price than the other markets, there is a high correlation in price movements within the Midwest area.

Exhibit 3-7: MISO Midwest Historical Electric Energy Prices January 2014 to September 2015



3.2.3 MISO Capacity Market

3.2.3.1 Overview

At the start of the MISO energy market in 2005, no mechanisms for capacity were included. In particular, the MISO tariff requirements did not include requirements to maintain minimum reserve margin. Rather, MISO relied on compliance with regional entities (such as Midwest Reliability Organization (MRO)) reserve margin targets and enforcement through state regulatory authorities. Although states had the authority for establishing reserve margins, coordination across states was not required.

Through 2009, reserve margins enforcement continued as a state function, however, a voluntary organization of load-serving entities, the Midwest planning reserve sharing group, was formed. Each member agreed to demonstrate sufficient generation to maintain resource adequacy and maintain firm transmission service to deliver generation. MISO overall reserve margins were in excess of minimum requirements.

In 2009, the MISO tariff changed to include a mandatory resource adequacy requirement. LSEs were required to demonstrate sufficient generation resources to meet the resource adequacy requirement for each month. MISO initiated a voluntary capacity market to facilitate the offering and procurement of “Aggregate Planning Resource Credits” (APRCs) to help market participants fulfill their resource adequacy requirements for a given planning month. The auctions were characterized by low volumes and low prices due to excess capacity throughout MISO.

In June 2012, the Federal Energy Regulatory Commission (FERC) conditionally approved a proposed new capacity market design by MISO. The design would add a locational capacity market mechanism, MISO’s resource adequacy construct, and also enable the ISO to

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develop seven local resource zones and establish minimum capacity requirements for each zone. Every LSE would be required to meet the reserve margin requirements for its zone by participating in a capacity auction, self-scheduling its own resources or opting out of the planning resource auction by submitting a fixed resource adequacy plan (FRAP). This initial proposal was rejected by FERC in September 2012, as MISO failed to show that the design is not discriminatory towards resource deficient existing LSEs, while resource deficient new LSEs are allowed to participate in MISO's energy and operating reserves market, or receive balance authority area services.

In February 2013, MISO submitted a new proposal which stated the following:

- New LSEs are going to be assigned existing local resource zones when possible
- Establish new zones for new LSEs when necessary by applying the same criteria used to establish existing local resource zones
- Develop capacity import and export limits
- Local reliability and local clearing requirements for each new zone based on the same criteria used for existing zones

In June 2013, MISO introduced a revised Resource Adequacy Construct (RAC) (or Resource Adequacy Requirements, RAR). The new Construct includes zonal capacity requirements to reflect the deliverability limitations to the system. However, without binding the zonal constraints in the 2013-2014 Planning Year Auction, the first annual Planning Resource Auction cleared at $1.05 per MW-day. The clearing price is consistent with very low prices from previous Voluntary Capacity Auctions (VCA).

On October 29, 2013, FERC approved MISO's modified proposal. Some commentators were concerned the current schedule poses great challenges for LSEs to secure the needed new capacity. FERC states that though that might be the case, LSEs can also use bilateral agreements or the annual planning resource auction to meet capacity requirements. According to FERC, MISO's accepted proposal would result in a less than 5% adjustment to LSEs' planning reserve margin requirements, which falls within the surplus capacity available in the 2013-2014 Planning Year.

Under the revised RAC, the demand in MISO capacity market is still defined by a minimum resource requirement and deficiency price, which results in a vertical demand curve. If the market is not in shortage, the vertical demand curve may lead to a clearing price close to zero. Significant volatility and uncertainty deter long-term investments by making it difficult to forecast capacity market revenues. The independent market monitor recommends a sloped demand curve for MISO's capacity market, although this has not been adopted.

The MISO RAR construct allows LSEs to meet their capacity obligations as defined by the sum of LSEs load projections and a Reserve Margin calculated by MISO or a state.

LSEs are able to meet these obligations by:

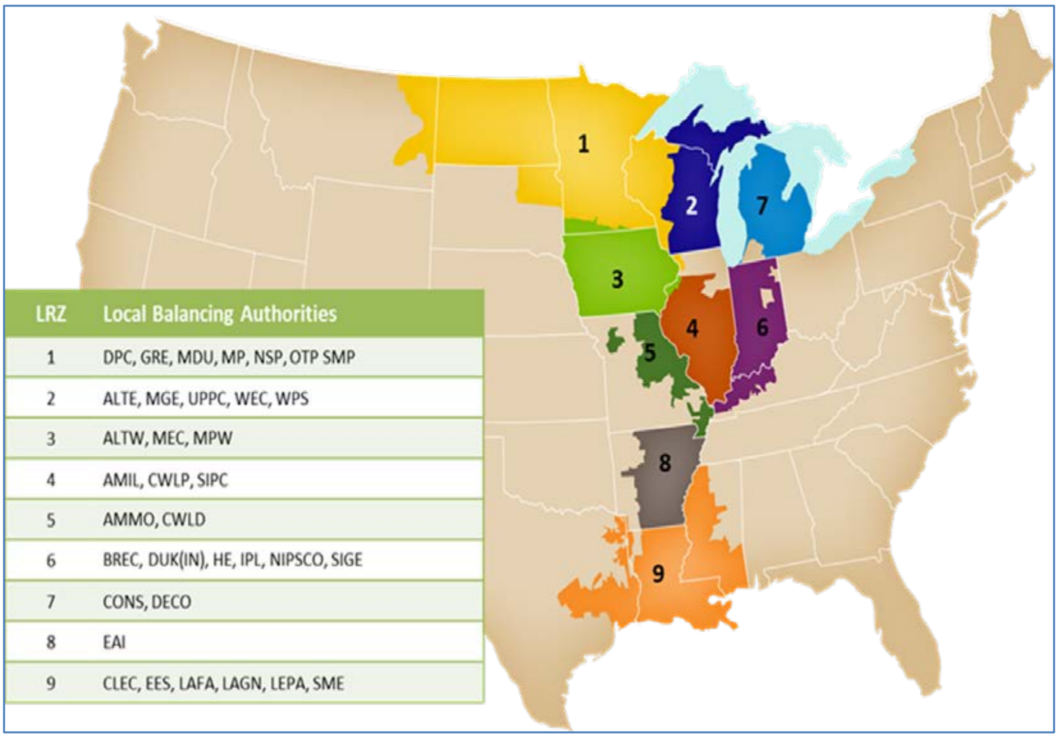
1. Acquiring capacity from annual planning resource auctions

2. Self-scheduling capacity resources

3. Submitting fixed resource adequacy plans

Today, MISO is divided into nine local resource zones (LRZs) as seen in Exhibit 3-8.

Exhibit 3-8: MISO Local Resource Zones



Source: MISO

MISO's resource adequacy construct provides compensation for resources not under a fixed resource adequacy plan (FRAP) for the value of having available energy in a particular geographic location. This construct aims to improve the reliability of the MISO electricity grid, especially during peak times when supply can be scarce. The capacity auction is prompt rather than forward looking like neighboring PJM markets, meaning that capacity for the June–May annual planning period is procured in April of that same year. Participants bid into the auction for zonal resource credits (ZRCs) that are equivalent to one MW of capacity. ZRCs are for one-year obligations. The bids are cleared through a single, sealed-bid clearing price auction against a vertical demand curve, unlike PJM and ISO-NE where bids are cleared against sloping demand curves. The RA construct began with the 2013–2014 auction period. Previously, MISO conducted a voluntary capacity market with significantly low capacity prices and no incentives for localization. The clearing price for each zone for the three resource adequacy (RA) auctions is outlined in Exhibit 3-9.

Exhibit 3-9: MISO Historical Capacity Prices ($/MW-Day)

Auction Period	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9
2013–2014	1.05	1.05	1.05	1.05	1.05	1.05	1.05	NA	NA
2014–2015	3.29	16.75	16.75	16.75	16.75	16.75	16.75	16.44	16.44
2015–2016	3.48	3.48	3.48	150	3.48	3.48	3.48	3.29	3.29

Source: MISO

Load serving entities (LSEs) and utilities must meet two reserve requirements in the RA auctions: the planning reserve margin requirement (PRMR) and the local clearing requirement (LCR). Exhibit 3-10 outlines how these requirements are determined and met in

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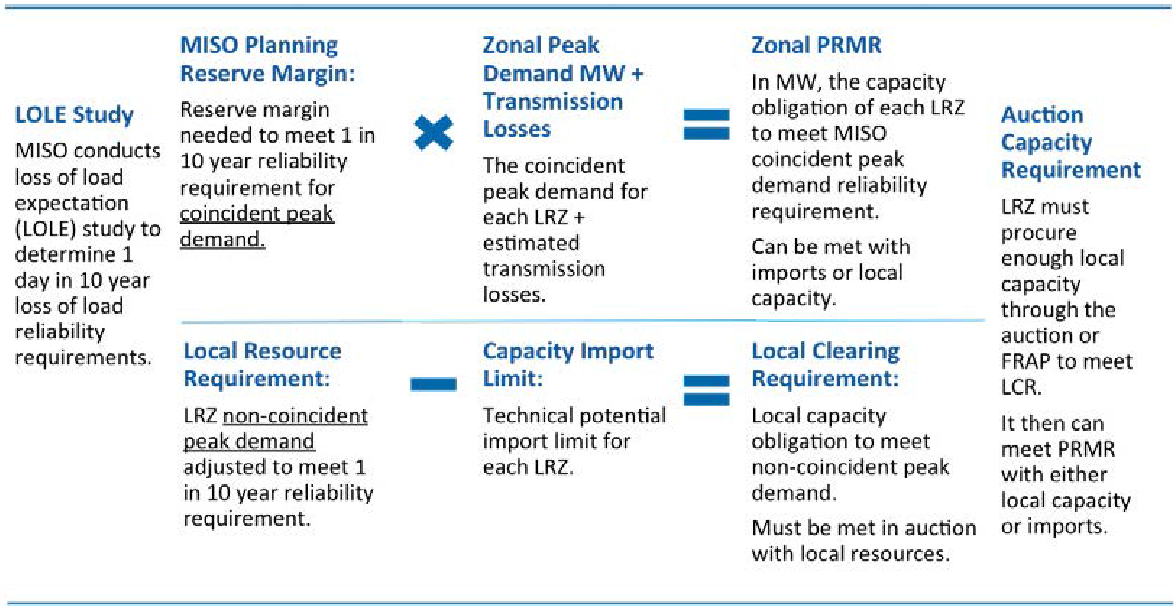
the auction. The LCR is the amount of capacity a zone must procure internally to meet its own peak demand requirements. The PRMR is the amount of capacity a zone must procure—which may include imports—to fulfill its obligation to meet MISO's peak demand reliability requirements. Resources to meet these requirements include both merchant resources that offer competitive bids in the auction and resources either contracted or developed by utilities. LSEs also can procure some or all of their requirements via a FRAP instead of RA auctions. The amount of resources under a FRAP in a given LRZ can either be removed from the overall requirements or can be assumed to be available in auctions at zero price.

Exhibit 3-10: MISO Capacity Obligations



3.2.3.2 Historical Prices

MISO's recent 2015–2016 capacity auction resulted in some significant shifts in pricing (Exhibit 3-11). Substantially lower clearing prices occurred across almost all of the system's nine zones, with the most notable exception of Zone 4 that saw a dramatic tenfold year-over-year increase.

Exhibit 3-11: MISO 2015-2016 Capacity Auction Results

Key		Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9
Coincident Peak Demand	A	16,525	12,429	8,876	9,518	8,176	17,592	20,522	7,424	23,035
Transmission Losses	B	581	238	244	211	143	530	653	156	466
Planning Reserve Margin	C	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%
PRMR	(A+B) x C	18,321	13,566	9,768	10,420	8,910	19,409	22,678	8,118	25,170
Local Resource Requirement	D	19,717	15,235	10,667	11,982	10,426	20,326	25,255	9,924	26,929
Capacity Import Limit	E	3,735	2,903	1,972	3,130	3,899	5,649	3,813	2,074	3,320
Local Clearing Requirement	F= D – E	15,982	12,332	8,695	8852	6527	14,677	21,442	7850	23,609
Total Offers Submitted		4,867	3,071	5,922	11,156	7,926	14,832	14,103	9,562	26,193
Total FRAP		14,494	11,817	4,113	838	0	4,853	9,456	397	2,261
Offers Cleared + FRAP	H>= F	18,495	14,497	9,813	8,852	7,885	19,015	23,515	8,526	25,762
Imports/ Exports	G	-175	-193	-45	1568	1026	394	-837	408	-592
Total Resources	(H+G)>=PRMR	18,320	14,304	9,768	10,420	8,911	19,409	22,678	8,934	25,170
Clearing Price $/MW-Day		$3.48	$3.48	$3.48	$150.00	$3.48	$3.48	$3.48	$3.29	$3.29

Sources: MISO and ICF

In the most basic terms, the capacity auction results were driven by relatively simple factors: higher opportunity cost-based bids in Zone 4, lower bids elsewhere, and more uncontracted competitive retail load. However, at a more detailed level, several related dynamics underscored bidding behavior. Independent power producers (IPPs) bid in capacity markets to cover their fixed and opportunity costs in contrast to utility-owned generation or contracted generation under a power purchase agreement (PPA) for which covering these costs is a far more secure proposition. Due to the higher concentration of IPPs and uncontracted retail load in Zone 4 (combined with higher expected costs for environmental compliance), expected energy margins are lower for merchant generators, and a higher offer price threshold (i.e., set based on a higher opportunity cost)—drove prices up dramatically. Conversely, in other zones, a greater proportion of capacity under fixed resource adequacy plans exerted downward pressure on prices. In Zone 7, particularly, a 320-MW decrease in planning reserve margin requirement added to price-lowering momentum, while a shift to less competitive bids and less uncontracted load dropped the clearing price further to $3.48/MW-day.

Going into the next auction, a number of factors will tighten the supply and demand balance. More than 2 GW of retirements are already anticipated, while the potential remains for an additional 15 percent of the region's overall coal capacity to retire. The retirement is because of the previously planned Mercury and Air Toxics Standards (MATS) compliance by 2016, although greater flexibility may now exist for these facilities, at least in the near term. Power plant operators in MISO are increasingly looking to interconnect to PJM to benefit from higher capacity prices there. In Zone 7 (Michigan) particularly, capacity losses are expected to increase prices, albeit moderately. However, given the inefficiencies in the current MISO capacity market structure—including the vertical demand curve, a lack of penalties for poor performance, a substantial number of low bids from regulated units, and volatility in the threshold for economic withholding—and the fact the majority of the capacity in MISO already is contracted; we do not expect a major recovery in capacity prices in the immediate term. This combination of factors may require eventual reform in the capacity market as current pricing signals are disconnected with MISO's shortage analysis. In the interim, state intervention could translate into more opportunity for new assets to enter into PPAs with utilities.

The forecasts presented herein reflect the "pure" capacity value reflective of the residual requirements to ensure return on investment for marginal resources added to maintain resource adequacy goals in the market.

3.3 Michigan Regulation Status

In the late 1990s, several states, including Michigan, began deregulating their electric utility markets in the hopes that competition in the generation and sale of electricity would drive down consumer prices. Michigan moved to a somewhat hybrid approach, initially allowing full retail choice, but not requiring divestiture of generation from load serving entities. In 2008, Michigan moved to a 10% cap on electric customer choice. Since that time, discussion to remove that cap has occurred and interest in this is rising again.

Utilities within Michigan which continue to operate as fully vertically integrated companies while participating in a centralized power market system, utilize a provision for power supply cost recovery (PSCR). Consumers Energy's recovery of power supply costs consists of purchased power, fuel, transmission, and certain environmental expenditures using both a fixed-base and variable rate that does not include any profit. The PSCR base is part of base rates, which also recover all of the authorized non-fuel related costs. Any under or over recovery of PSCR revenues are charged or refunded to the customer through an increase or decrease in a subsequent month's PSCR factor.

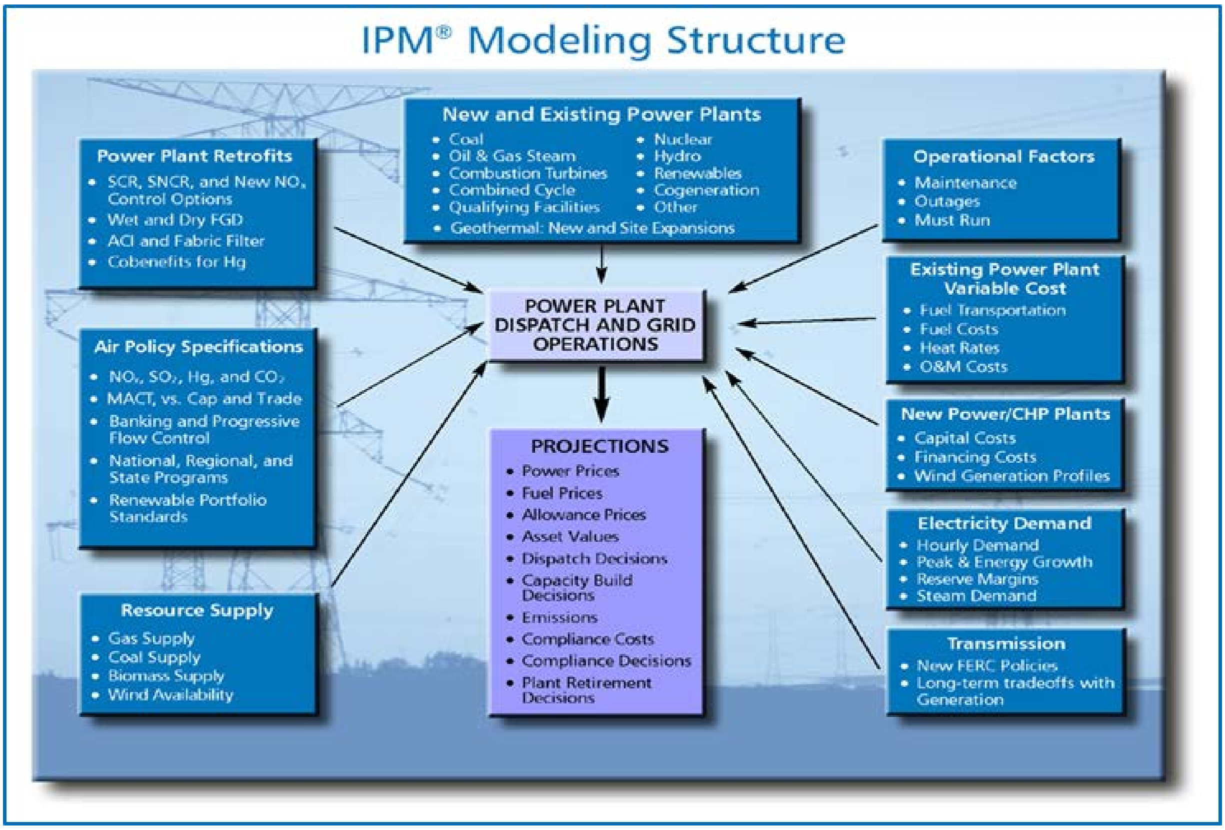
As such, unlike other fully deregulated markets, rate recovery in Michigan is based on the utility production cost expenditures rather than the costs to purchase power for the load serving entity.

3.4 Modeling Treatment

The analysis from 2018 to 2037 is conducted using ICF's widely used and accepted IPM® model. Developed by ICF, IPM® is a multi-regional, linear programming model of the US electric power sector with treatment of coal, natural gas, transmission, renewable and environmental issues. This sophisticated model develops an integrated set of national and regional forecasts.

ICF's IPM® is a production cost simulation model that analyzes wholesale power markets and assesses competitive market prices of electrical energy, based on an analysis of supply and demand fundamentals (Exhibit 3-12). IPM® projects zonal wholesale market power prices, power plant dispatch, fuel consumption and prices, inter-regional transmission flows, and environmental emissions and associated costs based on an analysis of the engineering economic fundamentals. The model does not extrapolate from historical conditions but for a given set of future conditions (new demand, new power plant costs, new fuel market conditions, new environmental regulations, and so on), which determine how the industry will function and provide a least cost optimization projection.

Exhibit 3-12: IPM Model Structure



Source: ICF

The model determines generation, and therefore production costs and prices, using a linear programming optimization routine with dynamic effects (i.e., it looks ahead at future years and simultaneously evaluates decisions over a specified time horizon). All major factors affecting wholesale electricity prices are explicitly modeled, including detailed modeling of existing and planned units, with careful consideration of fuel prices, environmental allowance and compliance costs, transmission constraints and operating constraints.

Based on the supply/demand balance in the context of the various factors discussed above, IPM® projects hourly spot prices of electric energy within a larger wholesale power market. IPM® also projects an annual “pure” capacity price.

3.4.1 Modeling of MISO

MISO is comprised of nine capacity zones (see Exhibit 3-8 above), with each load zone comprised of individual buses. For modeling purposes, ICF captures these areas as sub-regions assuming zonal interfaces rather than node-by-node characterization. ICF's zones match the Local Resource Zones (LRZ) of MISO for resource adequacy purposes however, for energy dispatch purposes, a finer characterization (as shown in Exhibit 3-13) is utilized.

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Exhibit 3-13: MISO Zonal Characterization within IPM

ICF Region	LRZ	BA Acronym	Local Balancing Authority (MISO)	Local Utility /Balancing Authority (EIA)
MISO-MN-WI	1	DPC	Dairy Land Power Cooperative	Dairyland Power Cooperative
	1	GRE	Great River Energy	Great River Energy
	1	MP	Minnesota Power	Minnesota Power Inc
	1	NSP	Northern States Power (Xcel Energy)	Northern States Power Co
	1	SMP	Southern Minnesota Municipal Association	Southern Minnesota Mun P Agny
MISO-ND	1	OTP	Otter Tail Power	Otter Tail Power Co
	1	MDU	Montana-Dakota Utilities	Montana-Dakota Utilities Co
MAIN-Wisconsin and Upper Michigan	2	ALTE	Alliant Energy – East[9]	Wisconsin Power & Light Co
	2	MGE	Madison Gas & Electric	Madison Gas & Electric Co
	2	UPPC	Upper Peninsula Power Company	Upper Peninsula Power Co
	2	WEC	Wisconsin Electric Power Company	Wisconsin Electric Power Co
	2	WPS	Wisconsin Public Service	Wisconsin Public Service Corp
MISO-IOWA-Alliant West	3	ALTW	Alliant Energy - West[10]	Interstate Power and Light Co
	3	MPW	Muscatine Power & Water	Board of Water Electric & Communications
MISO-IOWA-Mid America	3	MEC	MidAmerican Electric Company	MidAmerican Energy Co
MISO-Gateway-ILLinois	4	AMIL	Ameren - Illinois	Ameren Illinois Company
	4	CWLP	City Water Light & Power	City of Springfield - (IL)
	4	SIPC	Southern Illinois Power Cooperative	Southern Illinois Power Coop
MISO-Gateway-Missouri	5	AMMO	Ameren - Missouri[11]	Union Electric Co - (MO)
	5	CWLD	Columbia Water & Light District	City of Columbia - (MO)
MISO-Indiana	6	BREC	Big Rivers Electric Cooperative	Big Rivers Electric Corp
	6	DUK(IN)	Duke Energy - Indiana	Duke Energy Indiana Inc.
	6	HE	Hoosier Energy	Hoosier Energy R E C, Inc.
	6	IPL	Indianapolis Power & Light	Indianapolis Power & Light Co
	6	NIPSCO	Northern Indiana Public Service Company	Northern Indiana Pub Serv Co
	6	SIGE	Southern Indian Gas & Electric	Southern Indiana Gas & Elec Co
MISO-MECS	7	CONS	Consumers Energy	Consumers Energy
	7	DECO	Detroit Edison (DTE Electric)	Detroit Edison (DTE Electric)
Entergy-North	8	EAI	Entergy – Arkansas	Entergy Arkansas Inc.
Entergy-Central	9	EES	Entergy - MS, LA, TX	Entergy Mississippi Inc.
	9	EES	Entergy - MS, LA, TX	Entergy Louisiana Inc.
	9	LAGN	Louisiana Generation (NRG)	Louisiana Generating, LLC
	9	LEPA	Louisiana Energy & Power Authority	Louisiana Energy & Power Authority
Entergy-South	9	LAFA	Lafayette Utilities	City of Lafayette
	9	SME	South Mississippi Electric Power Association	South Mississippi Electric Power Association
Entergy-WOTAB	9	CLEC	Cleco	Cleco Power LLC
	9	EES	Entergy - MS, LA, TX	Entergy Texas Inc.

3.4.2 Summary of Key Market Assumptions

Power prices are influenced by many engineering, economic, and social factors. Key factors integrated into our analysis include:

- Peak demand and energy growth
- Infrastructure additions including generation and transmission
- Retirements and other restrictions on coal-fired or other generation resources
- New unit financing costs
- Fuel pricing, including coal and natural gas (discussed in Section 2)
- Renewable policy
- Climate and air emissions policy

These factors are discussed in more detail below. The assumptions around these factors are based on reasonable expectations given conditions today. Our analysis and modeling focuses on identifying the impact of the NEXUS Pipeline holding the assumed conditions for other parameters constant. The analysis does not consider the impact of uncertainty on any individual parameter or combined market conditions.

3.4.2.1 NEXUS Demand Levels and Demand Growth

Net Energy demand is expected to have positive, but slow growth over the forecast periods with MISO growing on average at 0.6% through 2037 and Zone 7 growing at 0.7% (Exhibit 3-14). This forecast is adopted directly from the MISO Independent Load Forecast, November 2014. In addition, ICF assumes that demand is responsive to significant price changes in the long-term such that demand growth levels may be impacted by significant price drivers such as the Clean Power Plan (CPP).

Exhibit 3-14: Zonal Annual Net Energy Demand projections for MISO

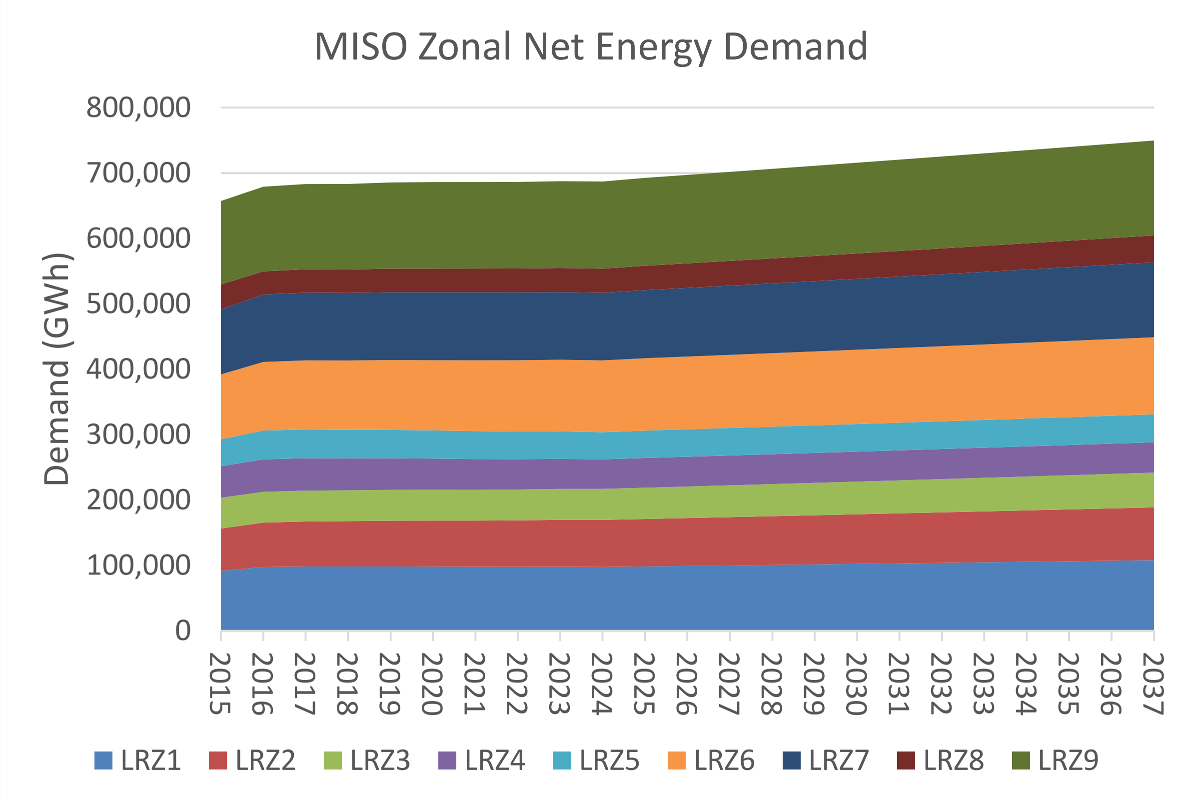
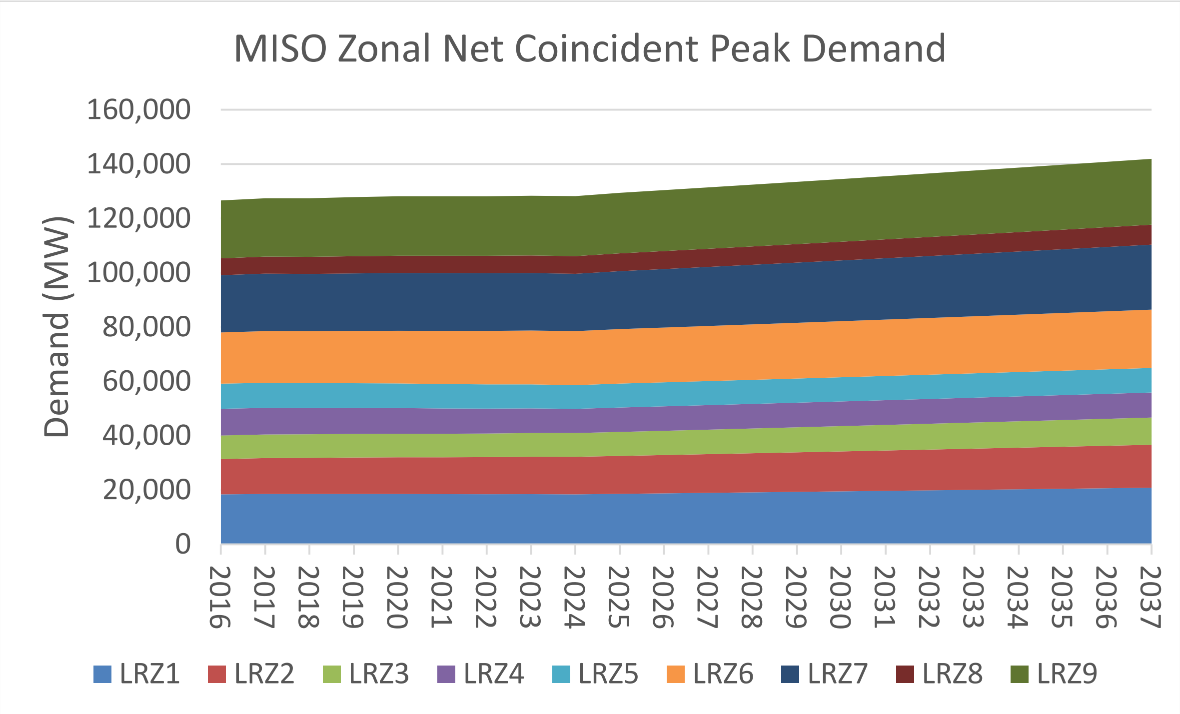


Exhibit 3-15: Zonal Annual Net Coincident Peak Demand projections for MISO



Peak demand grows at a slightly lower rate on average than energy in the forecast period with MISO coincident peak growing at 0.5% and Zone 7 (coincident peak) growing at 0.6% (Exhibit 3-15).

3.4.2.2 Changes in Supply Dynamics

Roughly 3.4 GW of coal capacity is expected to retire through 2020 based on current announcements. New gas additions, discussed above, are approximately equal to the amount of coal retirements expected based on these firm announcements. These retirements are due to combined air emissions regulations and economics. The combination of lower gas prices and stronger air emissions restrictions has made coal operation at numerous facilities uneconomic due to the significant capital investments for emissions control. In addition to the expected retirements shown, many coal facility retirements had already occurred leading into 2014.

Exhibit 3-16: MISO Expected Capacity Retirements

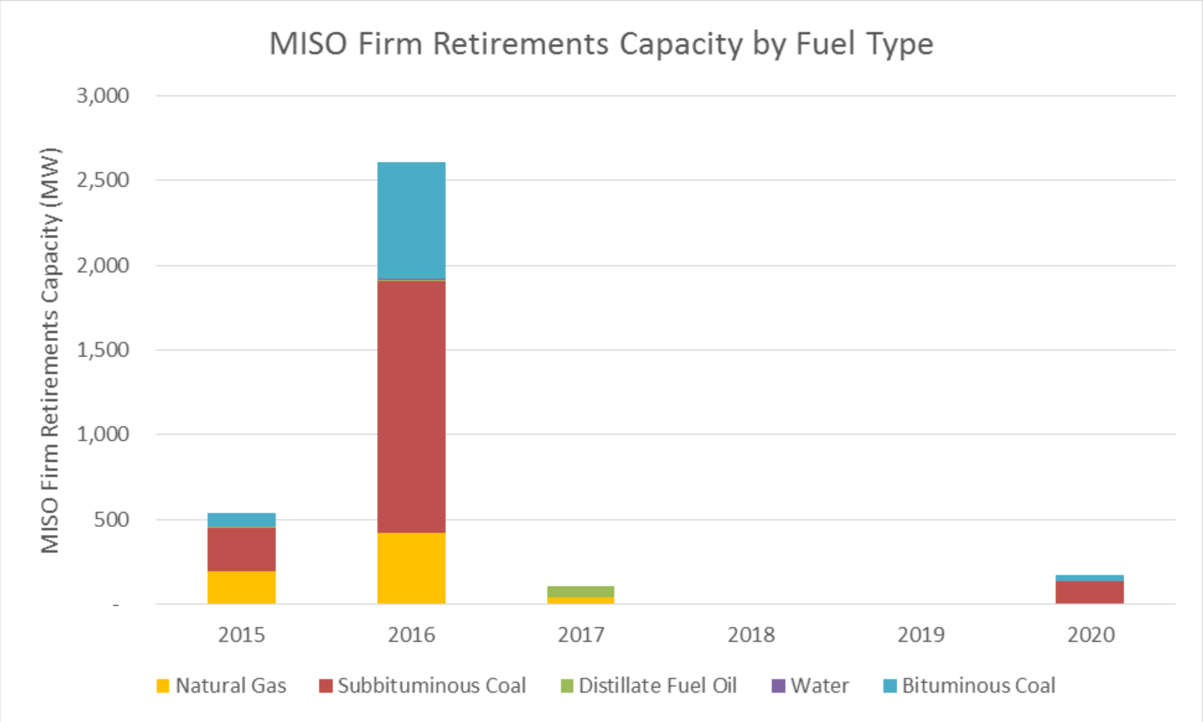


Exhibit 3-17: MISO Retirements Capacity Table (MW)

	2015	2016	2017	2018	2019	2020
Natural Gas	195	420	41	-	-	-
Subbituminous Coal	259	1,485	-	-	-	138
Distillate Fuel Oil	1	6	69	-	-	0
Water	1	6	-	-	-	-
Bituminous Coal	80	692	-	-	-	31
Total	536	2,610	110	-	-	169

Known capacity additions in the MISO market area are somewhat limited, however, significant wind additions are expected this year and next, and roughly 3.5GW of natural gas capacity is expected to be online through 2017.

Exhibit 3-18: Recently Operational Capacity in MISO

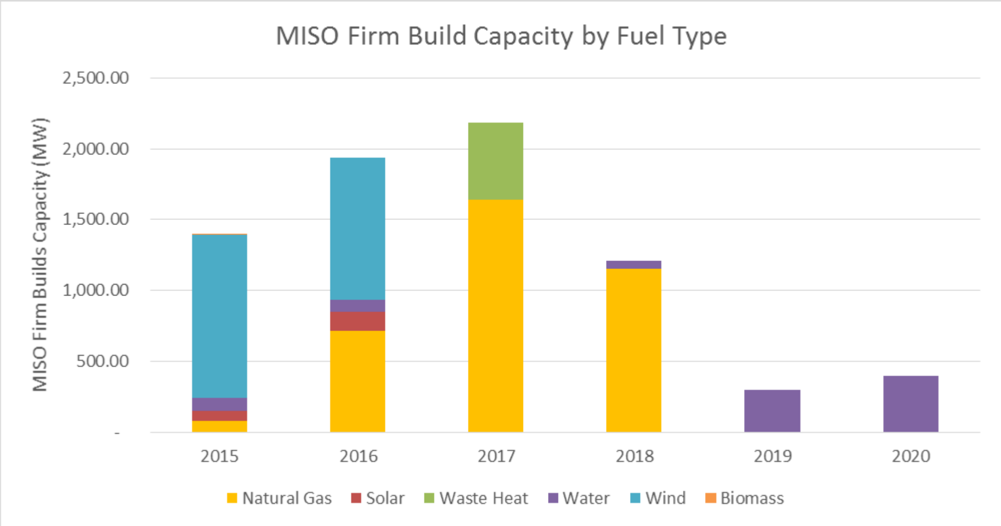


Exhibit 3-19: MISO Firm Build Capacity Table (MW)

	2015	2016	2017	2018	2019	2020
Natural Gas	81	716	1,639	1,150	-	-
Solar	68	132	-	-	-	-
Waste Heat	-	-	544	-	-	-
Water	89	85	-	60	298	397
Wind	1,153	1,008	-	-	-	-
Biomass	3	-	-	-	-	-
Total	1,394	1,941	2,183	1,210	298	397

3.4.2.3 Reserve Margin Targets

MISO wide reserve targets are expected to average slightly over 14 percent going forward.

Exhibit 3-20: MISO Wide Planning Reserves

Year	PRM
2015	14.3%
2016	14.4%
2017	14.5%
2024	14.2%

Source: MISO 2015 LOLE Study.

3.4.2.4 New Build Capital and Financing Costs

Beyond the known capacity expansion and retirements, the IPM model will add or subtract capacity to maintain reserves, ensure economic cost recovery for existing units, and ensure regulatory compliance with air emissions and renewable generation standards. A full set of fossil and renewable generation options are provided to IPM as inputs to select amongst for capacity expansion. Each zone has specific costs based equipment costs, land costs, labor costs, taxes and resource availability.

A source of uncertainty with respect to new power plant characteristics is the financing structure for new builds. ICF calculated the merchant cost of equity requirement to be approximately 13 percent. ICF has assessed the required rate of return for new entrants using the Capital Asset Pricing Model (CAPM). ICF assumes the required return on equity (ROE) for new entrants without long-term fixed price contracts (i.e., without long-term power sales contracts of 10 years or longer) is equal to publicly traded Independent Power Producer (IPPs) (e.g., NRG, Calpine, and Dynegy).

However, in the last few years, because of market risk perceptions and a more difficult financing environment, more and more development projects are “utility” or “hedged” in nature. This is in contrast to the early part of this decade when many of the projects were built with predominantly merchant exposure.

Going forward, ICF assumes new development projects will be pursued by investor owned utilities or by independent merchants on the basis of a power purchase agreement (PPA) with a credit-worthy IOU. This is based on several factors:

(1) The increasing share of contracted, hedged or utility capacity in the build mix relative to the early part of this decade when many of the projects were built with predominantly merchant exposure
(2) FERC buy side mitigation policy that allows for consideration of the effects of contracts
(3) The strong interest in state authorities in supporting activities which lower capacity prices including demand side (e.g. subsidizing energy efficiency) and supply side activities (signing contracts for supply) and transmission (accessing lower cost capacity sub zones)
(4) The availability of site and other conditions with lower costs than average for new units (making lower financing costs a proxy for lower capital costs for some projects)

Exhibit 3-21 below provides financing assumptions for new gas facilities. The financing assumptions for combustion turbines (CTs) reflect merchant financing in contrast to lower cost financing assumed for combined cycle gas turbines (CCGTs). This reflects the higher risks for CTS and the lesser likelihood that they will be contracted on similar terms as CCGTs.

3.4.2.5 Coal Pricing

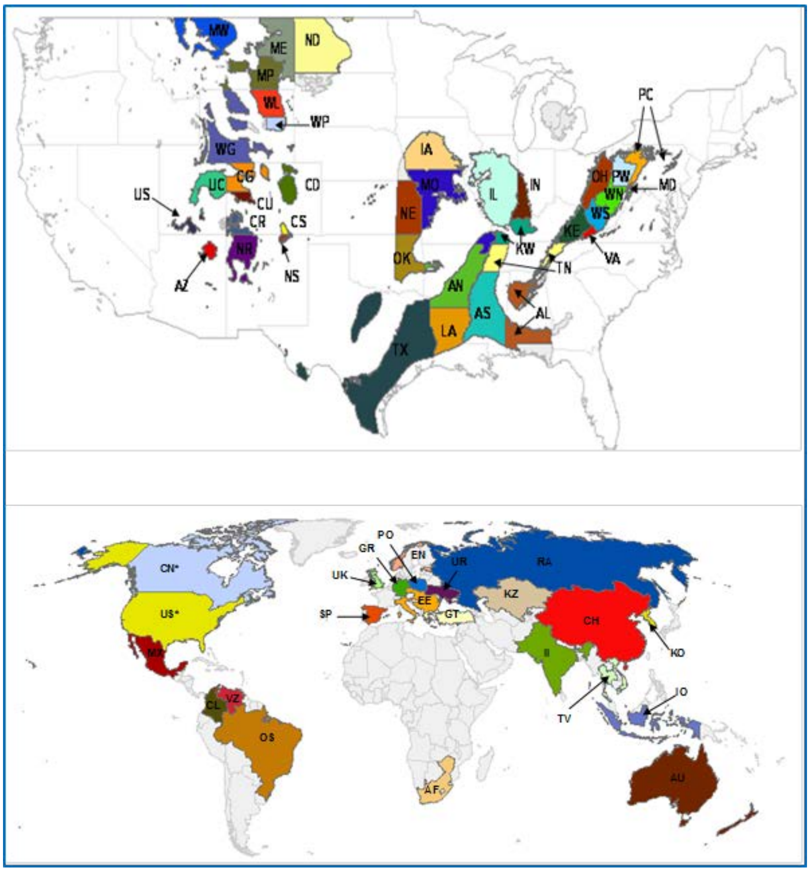
In IPM®, coal pricing is endogenously solved in the model. Coal resources are tracked and classified as being from one of 39 US coal supply regions or 25 international coal supply regions, as shown below in Exhibit 3-22.

Exhibit 3-21: New Plant Financing Assumptions for MISO

Input	Combustion Turbine	Combined Cycle/Cogen	Wind & Renewables
Input Assumptions			
Debt Life (years)	15	20	15
Book Life (years)	30	30	20
Nominal After Tax			
Equity Rate (%)	10.8%	10.8%	10.8%
Equity Ratio (%)	45.0%	45.0%	45.0%
Nominal Pre-Tax			
Debt Rate (%)	6.0%	6.0%	6.0%
Debt Ratio (%)	55.0%	55.0%	55.0%
Income Tax Rate (%)	40.8%	40.8%	40.8%
Inflation (%)	2.1%	2.1%	2.1%
Output			
Real Levelized Fixed Charge Rate (%)	11.16%	9.83%	11.16%
Nominal After tax Weighted Average Cost of Capital (%)	6.81%	6.81%	6.81%

Source: ICF

Exhibit 3-22: Coal Supply/Production Areas



Source: ICF

Coal supply curves for each of the 64 supply regions are created in CoalDOM®, an ICF modeling tool, by assigning every existing coal mine to one of 16 prototype coal costing models. A coal supply curve is generated for each coal type produced from each coal supply region for each year. The coal types are differentiated by rank and sulfur content. Coal types also differ in mercury and chlorine content depending on the source region. The coal supply curves are then used as inputs to IPM®. Coal plants in IPM® are assigned to one of 200 different coal demand regions that are defined by location and mode of delivery. A coal transportation matrix links supply and demand regions in IPM®, which determines the least cost means to meet power demand for coal as part of an integrated optimal solution for power, fuel, and emission markets.

ICF coal price projections in the near- to mid-term reflect some recovery for Northern Appalachian ("NAPP") coals from their currently depressed levels. However, Central Appalachian ("CAPP") and Illinois basin coals are not expected to increase significantly, although the reasons are different in each basin. For CAPP, prices are expected to remain low due to decreasing domestic demand and continuing low international prices. For the Illinois basin, continued development of longwall mines and oversupply are expected to keep prices flat. In the medium to longer term, decreased demand due to the new environmental regulations along with low natural gas prices will continue to put downward pressure on US coal prices.

At the same time there will be some upward pressure on coal prices as production costs continue to increase due to increased regulatory burden, safety inspections, more difficult geologic conditions, and extensive permitting delays for low cost mountain top removal mining. Another source of upward pressure on coal prices is the continued overseas interest in US thermal coal. However, with international coal prices at four year lows, the upward pressure on prices will not be felt until global coal demand recovers and international coal prices increase, which is not expected in the near term. Coal demand has been hit hard by low natural gas prices and coal plant retirements, and although coal consumption is down, it is not expected to decline significantly for the next five to ten years.

ICF projects that CAPP prices will increase only slightly in the near-term, but will stay flat long-term as demand for CAPP coal diminishes because of coal plant retirements and coal to gas switching keeps a lid on prices, while costs continue to creep upwards. CAPP prices remain flat as higher cost producers close down due to the low demand. The demand for high-sulfur Illinois basin and higher heat content NAPP coal will grow as more coal plants install scrubbers; thus, we expect prices for NAPP coal to increase in the near- to mid-term, but then remain fairly flat. In the longer term, NAPP prices will edge upwards as production costs continue to increase. Illinois basin prices will remain flat in real terms as miners over produce in the near-term and as longwall mining dominates in the basin in the long-term. Powder River Basin (PRB) coal prices will remain relatively flat over the long-term. ICF projects that PRB 8800 coal prices will stay between $10.3 and $13.0/ton (2013$) for the period 2014 to 2030.

3.4.2.6 Renewable Portfolio Standards

3.4.2.6.1 Michigan

Michigan is one of the 29 states with a binding renewable portfolio standard (RPS) policy in place. On October 6, 2008, the Clean, Renewable, and Efficient Energy Act (Public Act 295) was signed into law in Michigan, establishing a Renewable Energy Standard for the State of

Michigan. The Renewable Energy Standard requires Michigan electric providers to achieve a retail supply portfolio including at least ten percent renewable energy by 2015. The Act also included annual interim compliance requirements starting in 2012. Electric providers demonstrate compliance with renewable energy requirements through the purchase and/or production of Renewable Energy Credits (RECs).

Through new utility-owned generation, existing generation, and power purchase agreements, it is expected that this target will be met in 2015. In addition to the percentage-based energy requirements, a utility with more than 1 million retail customers as of January 1, 2008, (i.e., Consumers Energy) must meet a renewable energy capacity standard of 200 MW by December 31, 2013, and 500 MW by December 31, 2015. A utility with more than two million retail customers as of January 1, 2008, (i.e., DTE Electric) must meet a renewable energy capacity standard of 300 MW by December 31, 2013, and 600 MW by December 31, 2015. Energy production from these new renewable energy facilities can be counted towards the percentage-based component of the standard as well as the MW standard.

In 2014, Michigan had 1,163 MW of onshore wind, most of which was developed after the inception of P.A. 295[9]. Negotiated contracts for wind have come in below expected costs, with some projects under $50/MWh. Many utilities in Michigan no longer have a renewable energy surcharge due to lower than expected costs.[10]

There are various forms of renewable generation that qualify for RECs in Michigan including geothermal electric, solar thermal electric, solar photovoltaics, wind (all), biomass, hydroelectric, municipal solid waste, combined heat & power, landfill gas, tidal, wave, anaerobic digestion , landfill gas, coal fired with carbon capture and storage, and gasification. Based on project costs and resource quality, the majority of RECs generated to comply with P.A. 295 will come from wind power. However, as the installed cost of solar continues to decrease, solar generation could become more cost effective than wind and contribute significantly to future RPS requirements in Michigan. Both of these resources are variable and must be balanced by dispatchable generation such as coal and natural gas-fired facilities.

Although there have been calls by the Michigan governor to update the existing 10% standard, the current energy plan maintains a 10% mandate which is assumed in the modeling as a forward target.

3.4.2.6.2 Modeling Renewable Energy Standards

Many RPS regions are oversupplied, while others still offer development opportunities. The supply/demand position is determined based on RPS policy requirements and generation from eligible renewable projects. In many cases, states allow imports of renewables from other states to qualify toward their goals. As such, ICF models regional targets consistent with overall state goals. Under this structure, Michigan can source its renewables from any area in the Midwest within the MISO footprint.

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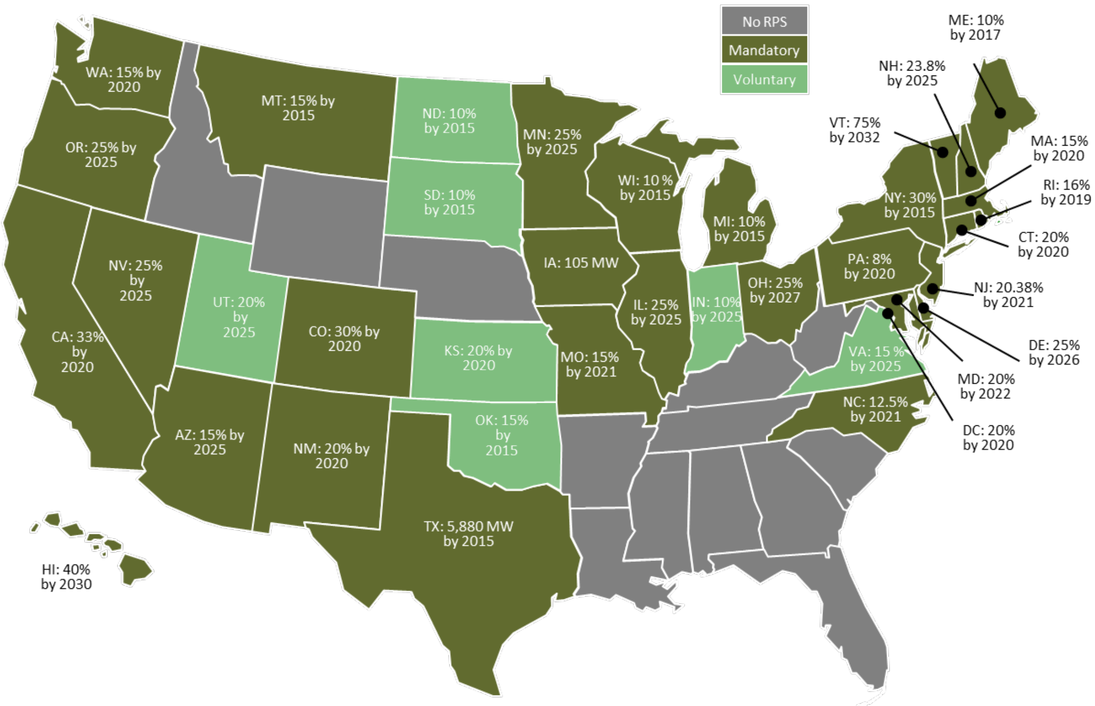
[9] Michigan Public Service Commission, "Report on the Implementation of the P.A. 295 Renewable Energy Standard and the Cost-Effectiveness of the Energy Standards," 2014.

[10] Michigan Public Service Commission, "Report on the Implementation of the P.A. 295 Renewable Energy Standard and the Cost-Effectiveness of the Energy Standards," 2014.

Exhibit 3-23: State Renewable Compliance Standards, 2015



3.4.2.6.3 Renewable Resource Incentives

ICF's analysis includes key federal incentives for renewables.

- The Investment Tax Credit (ITC) is a 30 percent credit available to solar units, distributed wind systems, and geothermal heat pumps (distributed generation, aside from solar PV, is not modeled in IPM®). Under current policy, all units placed in service through the end of 2016 are eligible. After 2016, ICF assumes that ITC will fall to 10% and will remain at that level in perpetuity.
- A Production Tax Credit (PTC) is no longer modeled for unplanned renewable builds. The December 2014 Tax Extenders bill effectively only extended the PTC for three weeks through the end of 2014 and ICF assumes that no additional unplanned builds in our modeling are economic without the PTC.
- The Modified Accelerated Cost-Recovery System (MACRS) allows for full depreciation for wind, combined heat and power (CHP), geothermal, fuel cells, and solar units over a five-year period. The biomass property class life is set at seven years. In IPM®, MACRS is captured in the capital charge rate, effectively lowering the revenue requirements for renewable units.

3.4.2.7 Federal / Regional Environmental Regulations

Environmental regulations have become increasingly important to U.S. power markets over the past decade. Individual states and regional coalitions are moving ahead with their own environmental requirements on generators, including implementation of the Regional Greenhouse Gas Initiative (RGGI) in the northeast. The U.S. Environmental Protection Agency (EPA) is also very active in developing a range of new regulations from the Clean Air Act, Clean Water Act and Resource Conservation and Recovery Act (RCRA). Uncertainty remains around the scope, timing, and compliance options for these regulations since some have yet to be finalized and others, while final, are currently being challenged or likely to be challenged in court.

ICF has incorporated federal regulations that have been promulgated, covering regulations for SO2, NOx, CO2, and hazardous air pollutants as summarized in Exhibit 3-24. We have also included state and multi-state CO2 programs in California and in the member states of RGGI.[11]

Exhibit 3-24: Environmental Assumptions Overview

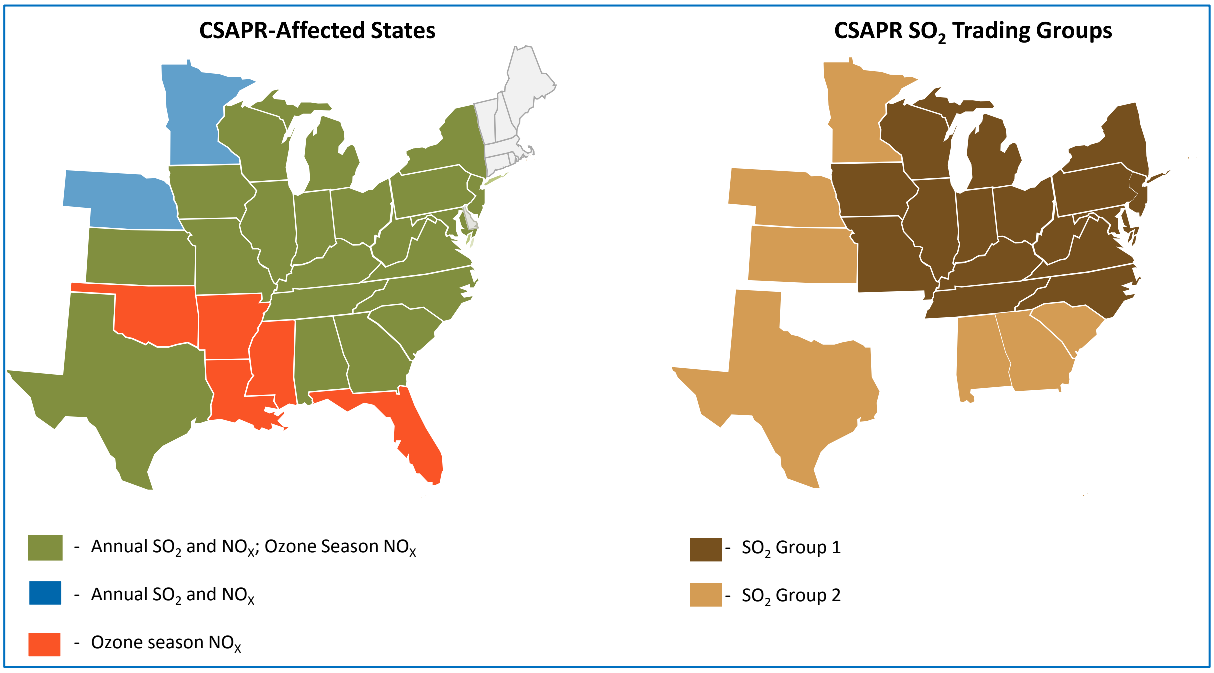
Federal Regulation	Covered Pollutants	Timing
Cross-State Air Pollution Rule (CSAPR)	SO2 and NOx	2015 for Phase 1 and 2017 for Phase 2
Mercury and Air Toxics Standards (MATS) Rule	Mercury, acid gases (proxy HCl), and particulate matter	2016
CCR (coal combustion residuals, coal ash) Disposal		2018
Clean Power Plan	CO2	2022
Water Intake Structures, or 316(b)		2025

3.4.3 Cross-State Air Pollution Rule

In July 2011, EPA finalized the Cross-State Air Pollution Rule (“CSAPR”) to replace the vacated Clean Air Interstate Rule (CAIR). Both CAIR and CSAPR were designed as a tool to help states in achieving attainment with the 1997 National Ambient Air Quality Standards (NAAQS) for ozone and the 1997 and 2006 NAAQS for fine particulates (PM2.5). After a number of court delays, CSAPR was allowed to proceed with the Phase 1 standards beginning January 1, 2015 for the annual NO_X and SO_2 program and May 1, 2015 for the ozone season NO_X program. Phase 2 standards begin January 1, 2017 for annual NO_X and SO_2 and May 1, 2017 for the ozone NO_X program. As seen in Exhibit 3-25 below, most of the Eastern and Midwestern states are subject to the new CSAPR rule.

[11] ICF assumes that the California and RGGI CO_2 programs will be in effect until 2022, at which point the states comply with the Clean Power Plan.

Exhibit 3-25: State Overview of CSAPR



CSAPR establishes four trading programs at the state level, setting emission budgets for:

- Annual SO_2 emissions to address PM (allocated among two "Trading Groups" of affected States)
- Annual NO_X emissions to address PM
- Ozone Season NO_x (May 1 – September 30) to address 8-hour ozone
- The four trading programs start with all-new SO_2 and NO_X "currencies," so allowances banked from the Title IV Acid Rain program and the CAIR program have no value in the new program. EPA developed the state budgets using a combination of power sector and air quality modeling.

Exhibit 3-26 shows the current assumed Phase 1 and Phase 2 CSAPR limits and timing.

Exhibit 3-26: Cross-State Air Pollution Rule Requirements

Annual NOx (Million Tons)	**Ozone Season NOx (Million Tons)**	**SO_2 (Million Tons)**
CSAPR	CSAPR	CSAPR
28 Eastern States + DC	28 Eastern States + DC	28 Eastern States + DC
In 2015, states are able to fully trade allowances with other states in their region. Starting in 2017, interstate trading is limited.		
2015: 1.270 **2017: 1.207**	2015: 0.628 2017: 0.586	Tier 1 SO2 States: 2015: 1.552 2017: 1.373 Tier 2 SO2 States 2015: 0.918 2017: 0.892

3.4.4 Mercury and Air Toxics Standards (MATS)

EPA finalized the Mercury and Air Toxics Standards Rule (MATS) in December 2011. The Rule was developed under Section 112 of the Clean Air Act, which defines a number of hazardous air pollutants (HAPs). Under this section, EPA is charged with developing regulations to reduce listed pollutant emissions. Pollutants regulated under Section 112 cannot be reduced using a cap and trade system. Instead, the EPA must determine a maximum achievable control technology (MACT) limitation based on the top 12 percent of existing units for each pollutant. The regulation takes the form of an emission standard at the facility-level. As such, units/facilities will either have to control emissions or face retirement. The final MATS Rule specifies emission rate limits for 3 pollutant classes, requiring control of mercury, acid gases (represented by HCl), and particulates as surrogates for over 100 controlled pollutants.

Michigan led a coalition of states and industry groups in arguing that the EPA did not properly consider the costs of compliance for the MATS regulations when crafting the rules. On June 29, 2015, the U.S. Supreme Court ruled against EPA on the question of cost as pertaining to MATS, remanding the case back to the Circuit Court. The DC Circuit Court must now determine whether to remand the rule to EPA and allow it to address the Supreme Court's challenges, or vacate the rule and restart the rulemaking process. EPA has said publicly that it will request a remand without vacatur and provide with that request a plan to respond to the Supreme Court's ruling.

The impact of the ruling on the nation's power supply is expected to be somewhat muted, given that power companies had already largely chosen to retire or retrofit coal plants that would be impacted by the rule, despite the uncertainty that surrounded its legality. Certain facilities which had already sought extensions to the original MATS deadline for retrofit purposes may now have more flexibility in their operations. This affects roughly 26 GW of capacity in the US.

While uncertainty remains about the court's decision and EPA's response, this analysis assumes implementation of MATS as finalized by EPA on December 21, 2011. Units are therefore required to meet the mercury (Hg) and acid gas (proxy HCl) standards in the rule. For compliance with the particulates standards (PM), each unit must be equipped with a fabric filter or an adequately sized Electrostatic Precipitator (ESP), upgrade its ESP, or add a new fabric filter. States with existing Hg rules proceed as planned, so long as they meet minimum requirement as defined by the federal MACT. See Exhibit 3- for a summary of ICF assumptions on air toxic regulations.

Exhibit 3-27: Assumed MATS Regulations

MATS Start Year	ICF Treatment
2016	Maximum achievable control technology (MACT) standards consistent with those set by EPA in its final rule, released December 21, 2011. Units are required to meet the Hg and HCl standards in the final rule. For PM compliance, units are required to upgrade their ESP or install a FF based on EPA's modeling assumptions for the final rule to meet the filterable PM standard.

3.4.5 Clean Power Plan

On August 3, 2015 EPA released the final Clean Power Plan[12] which specifies carbon dioxide emission rate guidelines for existing stationary generation sources. EPA derived these standards through a multi-step Best Standard of Emissions Reductions (BSER) approach which began with 2012 historical generation and emissions and layered in the following elements:[13]

1) Efficiency improvements at coal-fired plants
2) Increasing dispatch of existing natural gas combined cycle generators to 75% capacity factor
3) Increasing the penetration of Renewable resources

As part of the final rule, EPA also released mass caps that cover affected sources as an alternative to the emission rate standards. EPA requires that states meet the required standards beginning in 2022, with the final standards to be reached by 2030. The rate and mass cap limits for Michigan are shown in Exhibit 3-28 listed below:

[12] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, Environmental Protection Agency
http://www2.epa.gov/sites/production/files/2015-08/documents/cpp-final-rule.pdf
[13] For details please see:
http://www.epa.gov/airquality/cpp/tsd-cpp-emission-performance-rate-goal-computation.pdf
http://www.epa.gov/airquality/cpp/tsd-cpp-emission-performance-rate-goal-computation-appendix-1-5.xlsx

Exhibit 3-28: Michigan Annual Rate and Mass Cap Limits Under CPP

Year	State Goals (lbs/MWh)	Affected Source Mass Goals (Short Tons)
2022	1,526	59,161,223
2023	1,475	57,047,231
2024	1,404	54,354,312
2025	1,365	53,213,469
2026	1,326	51,979,026
2027	1,286	50,488,171
2028	1,247	49,592,779
2029	1,208	48,620,988
2030 +	1,169	47,544,063

States must develop plans to comply with the Clean Power Plan. The plans will lay out the regulations and programs that the states will adopt to reach their specified targets, and they must declare whether the state will adopt an emission rate or a mass-based standard. Final plans are due to EPA by 2018, at which point EPA will review them to determine if they will achieve the required standards. While uncertainty remains regarding the form of the final form of CPP and how states will choose to comply, this analysis represents the Clean Power Plan as a mass cap over qualifying facilities (existing fossil-fired electric generating units) for all states. Compliance must be demonstrated at the state level with no provisions made for cross-state trading of allowances (compliance measures).

In general, the impact of CPP is expected to drive movement to gas-fired generation (versus other fossil sources) at a faster rate than would otherwise occur. Likewise, renewables and demand side alternatives are expected to be more attractive resources from both a cost and emissions perspective.

3.4.6 Other Environmental Regulations

The Clean Water Act (CWA, 1972) includes several key provisions impacting power markets. It prohibits unauthorized discharge of pollutants from point sources to US waters, it requires National Pollutant Discharge Elimination System (NPDES) permits that regulate the discharge of pollutants (issued by EPA, state or tribe), requires EPA to develops effluent limitation guidelines and standards, and requires states to develop water quality standards that are the basis for the limitations required in NPDES permits.

Section 316(b) of the CWA addresses cooling water withdrawals, as opposed to discharges, by point sources subject to the NPDES program. It grants EPA the authority to regulate “location, design, construction and capacity of cooling water intake structures” to ensure that these structures reflect “the best technology available (BTA) for minimizing adverse environmental impact.”

In May 2014, the EPA released a final Phase II rule under 316(b) for large existing generating units, including coal-fired, nuclear, and other steam units that will require compliance investments at facilities with once-through intake systems. Under the rule, compliance requirements will be determined by each state. Compliance with the new regulation will be phased in over time as units come up for new NPDES permits. Exhibit 3-29 below summarizes ICF’s assumptions.

Exhibit 3-29: Assumed Water Intake Structure Requirements

Compliance Year	**2025**
Once-through cooling systems	[1] Plants with once-through cooling in the following states must install cooling towers: CA, OR, WA, NJ, NY, MA [2] Plants with once-through cooling in other states must install a representative alternative compliance option, such as nets with fish handling, booms, velocity caps, etc.
Re-circulating systems with cooling pond/canal	Exempted

Following the ash pond failure at TVA’s Kingston plant in 2008, EPA released a proposed rule in April 2010 for the handling of ash or coal combustion residuals (CCRs) under the Resource Conservation and Recovery Act (RCRA). EPA’s finalized the rule for the management of coal combustion residuals in December 2014. The rule was finalized under RCRA Subtitle D (governing solid and municipal waste management and disposal), which means the CCRs are classified as solid waste and not as hazardous waste. Exhibit 3-30 below summarizes ICF’s assumptions for compliance requirements for the CCR rule.

Exhibit 3-30: Assumed CCR Rule Compliance Requirements

Timing:	**2018**
Units with surface-based impoundment	(1) Dry collection modifications (2) Close/cap ash pond (3) New wastewater treatment facilities
Units that landfill	Upgrade wastewater treatment facilities for scrubbed units only (in response to effluent guidelines)
Ash is not treated as hazardous	
Beneficial use of ash continues	

4 Impacts of the NEXUS Pipeline on Michigan Natural Gas and Electricity Markets

While the NEXUS Pipeline will have a number of impacts on Michigan energy markets, including improvements in natural gas supply reliability and natural gas supply diversity, the major impacts of the pipeline include reductions in natural gas prices in Michigan, spurred in large part by improved access to Marcellus and Utica gas supplies at supply basin prices. ICF's analysis indicates that the decline in natural gas prices will have significant impacts on both natural gas and power markets in Michigan.

4.1 Impact of NEXUS Pipeline on Michigan Natural Gas Costs

The decrease in natural gas prices due to the completion of NEXUS Pipeline will reduce natural gas supply costs for all natural gas consumers in Michigan including DTE Electric.

ICF has used two alternative approaches to determining the impact of the decline in natural gas prices on Michigan energy consumers. The first approach values Michigan natural gas consumption at Michigan Citygate prices while the second approach considers a multiple supply points.

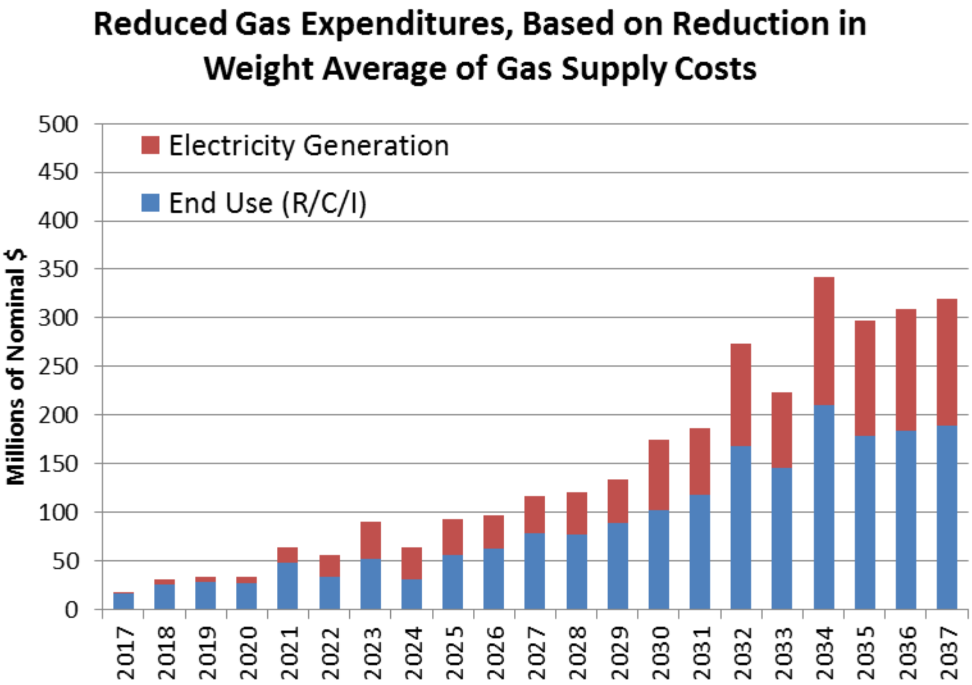
For the first approach, based on projected consumption and the changes in Michigan Citygate prices, the addition of the NEXUS Pipeline is projected to reduce the value of natural gas delivered to Michigan delivery points by a total of $4.4 billion between 2018 and 2037. Approximately $3.2 billion of the total reduction in natural gas value is projected to occur in the end use sectors (residential, commercial, and industrial), while the value of natural gas delivered to the power sector is reduced by $1.2 billion.

However, valuing natural gas at the Michigan Citygate prices is likely to overstate actual reductions in natural gas expenditures. Because much of the natural gas consumed in Michigan is purchased at market centers outside of Michigan and transported by the purchaser to Michigan markets, the actual savings in natural gas supply costs will depend on the composition of the natural gas supply purchase portfolio for Michigan consumers. Major natural gas purchasers in Michigan, including the natural gas utilities such as DTE Gas and Consumers Gas, purchase natural gas from a portfolio of different supply points that are delivered into Michigan via a variety of pipeline systems.

For the second approach, in order to assess the impact of the NEXUS Pipeline on natural gas costs, ICF developed a simple portfolio model based on natural gas prices at the original source of the natural gas, plus the cost of pipeline transportation to Michigan markets. When weighted by the percentage of natural gas volumes sourced at different supply points, the average decline in gas purchase price is projected to average about $0.12 per MMBtu, leading to a net reduction in natural gas purchase costs of about $3.1 billion (Exhibit 4-1). About $1.9 billion of the total reduction in natural gas purchase costs will benefit end-use consumers in the residential, commercial and industrial sectors, while the remaining $1.2 billion reduction in gas costs would benefit power producers using natural gas.

This second approach likely understates reliance on Michigan Citygate prices, and is expected to understate the actual natural gas supply cost savings associated with the development of the NEXUS Pipeline.

Exhibit 4-1: Annual Cost Savings to Michigan Gas Consumers (Millions of Nominal $)



Source: ICF

4.2 Impacts of NEXUS in Electric Markets in Michigan (MISO Zone 7)

Using the IPM capacity expansion and production simulation tool, ICF has examined the impact to the Zone 7 area of the MISO market of a change in delivered natural gas prices due to the construction and operation of the proposed NEXUS Pipeline. ICF's analysis is limited to a wholesale energy and capacity market review and does not consider the implications of purchases of firm gas supply to any specific purchaser, nor does it consider a retail customer impact to end users in the Michigan market area.

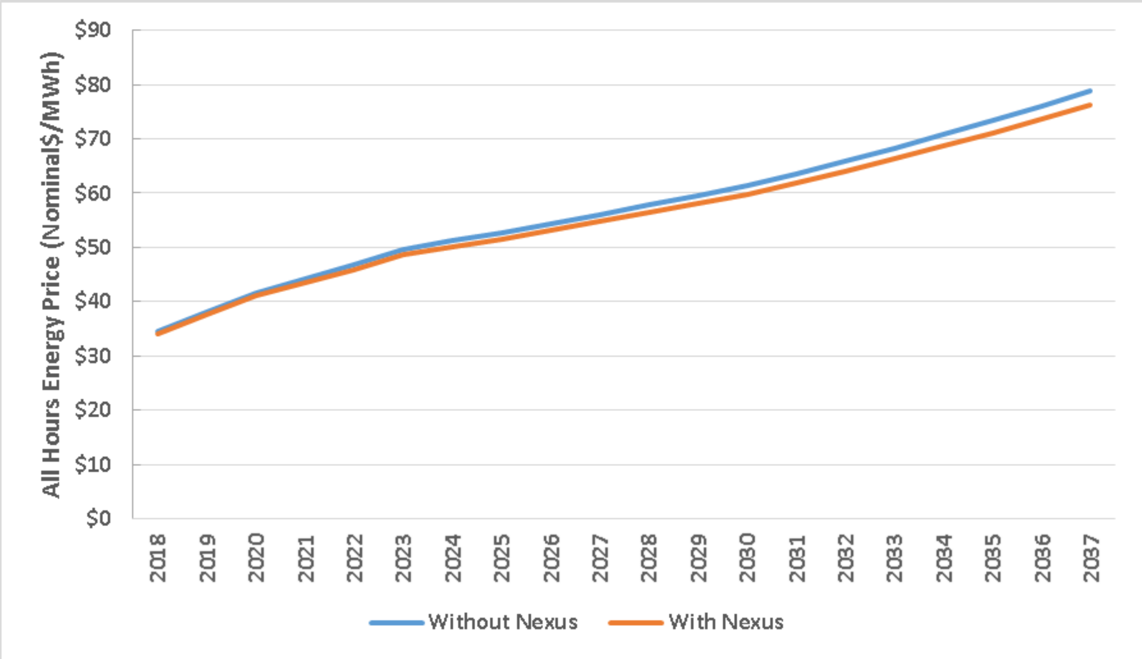
Retail cost savings require further analysis to consider in full. Michigan utilizes a hybrid approach to retail choice which allows some retail choice (capped at 10%), but is not a full deregulated model. Further, Michigan, unlike other states allowing retail access, has not separated electric generation from the utility. As such, the customer costs for the up to 10% of load (roughly 6,500 mostly commercial and industrial customers in 2014)[14] using retail choice would experience a savings impact consistent with the change in wholesale market prices, the large majority of customers (90%) experience utility rates. Utility savings will largely be tied to utility production cost savings rather than the power purchase cost savings, at least to the extent that the utility relies entirely on self-generation. As such, the natural gas cost savings represents a proxy for electric customer impact. Though retail customer impact is not analyzed here, a conservative estimation of consumer savings is considered – gas production cost savings. This is conservative given that 1) it does not account for the roughly 10% of Michigan customers who are not utility customers; 2) it does not reflect the potential for change to the retail choice provisions in Michigan which could result in more

[14] FAQ: The debate over Michigan's electricity deregulation, By David Eggert, Associated Press September 26, 2015.

customer exposed to customer risks it does not reflect the full market impact to retail choice customers; and 3) it does not capture the displacement effect on the purchase price of higher cost resources such as net imports, or for the displacement of coal purchases which would be more expensive. The production costs savings are however a direct result of the transactions occurring within the centrally dispatched MISO market. That is, the dispatch of any individual facility is on a centralized competitive market based system to provide efficient dispatch on a broad basis across all of Michigan. While the marginal costs are not recoverable through rates, the modeling of marginal dispatch in the MISO market is necessary to understand the change on generation needs.

The largest impact of the NEXUS pipeline is the anticipated reduction in wholesale power. Exhibit 4-2 provides an illustration of Zone 7's all hours electric energy pricing in the day ahead market through 2037.

Exhibit 4-2: Zone 7 All Hours Energy Price Projections



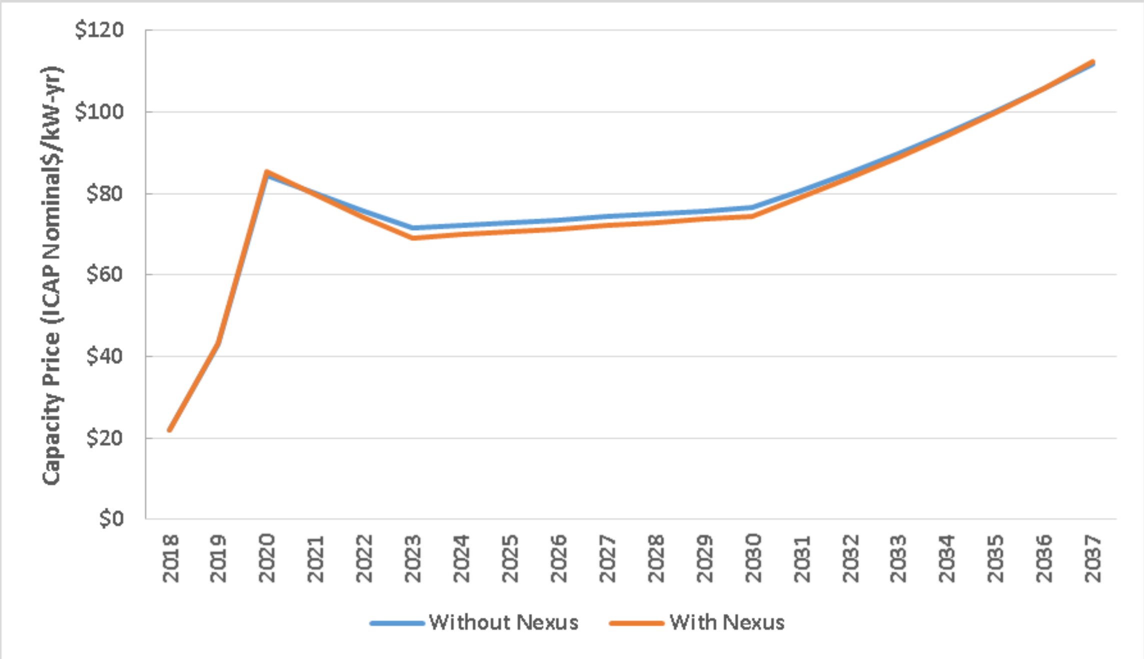
Source: ICF

Going forward, gas-fired generation resources are anticipated to become more dominant as the marginal fuel source. This is particularly true with expected response to the Clean Power Plan which will limit the ability of coal facilities to generate economically to the extent seen historically. With gas resources already dominating peak hour prices, and the increase in gas on the margin in other hours over time, the impact of the change in natural gas prices in Michigan due to the NEXUS Pipeline will be directly translated to the wholesale energy market price.

Overall, the resource mix with and without the NEXUS Pipeline is not anticipated to change significantly over the 20 year term of the analysis, and hence implied market heat rates are not anticipated to move significantly should the NEXUS Pipeline be built. However, the reduction in gas costs associated with NEXUS does encourage a movement to gas supply resources in Michigan earlier than would otherwise be the case, such that there are slight shifts in the timing of new resource additions. Though the amount of resources is not significantly different in the long-term, the anticipated generation (reflected through the utilization of new resources) is greater in Michigan given lower expected gas prices. The average expected change in all hours energy price between 2018 and 2037 is $1.44/MWh; this is based on the expected average change in the MichCon price of $0.21/MMBtu.

Capacity markets will also be affected by the natural gas price movement, but to a lesser extent than the energy markets. Capacity prices as modeled reflect the “pure” capacity value in a competitive market structure, i.e., the value of the marginal capacity resource as reflected by full recovery of the expected normal financial return of and on the capital investment. Hence, capacity prices reflect the income requirement to build new generation to satisfy reserve requirements over and above the energy returns earned by the capacity resource (i.e. the net cost of new entry). In this case, capacity prices experience a slight decline on average over the forecast period. Exhibit 4-3 presents expected capacity market price changes between the cases between 2018 and 2037. On average, the expected capacity market prices with NEXUS are $1.11/kW-yr lower than the case without NEXUS.

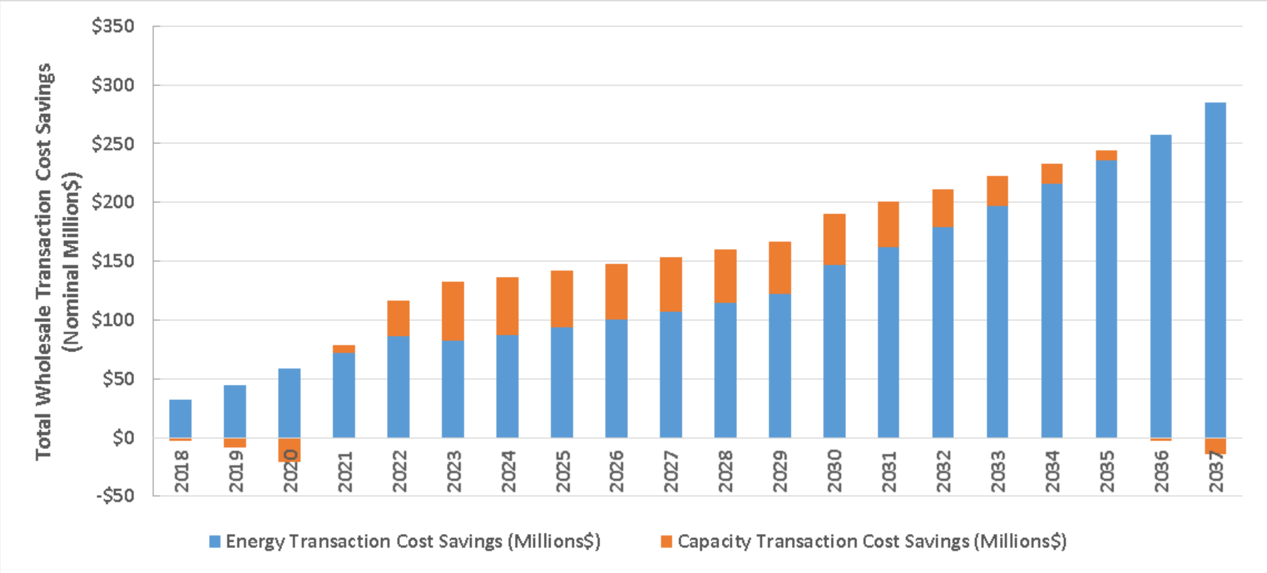
Exhibit 4-3: Zone 7 Capacity Price Projections



Source: ICF

Overall, wholesale transactions are dominated by energy purchase in the market. On a spot basis, load serving entities would on average save 158 million dollars (average nominal) between 2018 and 2037, ranging from $29 million to a maximum annual savings of $271 million. In total, this reflects a cumulative savings of $3.2 billion (nominal) in total or $1.4 billion on a net present value basis (assuming 7.1% annual carrying charge). Annual expected savings are shown in Exhibit 4-4.

Exhibit 4-4: Annual Expected Wholesale Energy Transaction Cost Savings



Source: ICF

The benefits discussed are anticipated to accrue to all load serving entities in the Michigan market equitably as load serving entities purchase power through the MISO central market system. These savings are entirely based on the anticipated movement in the average Michigan delivered gas prices but do not assume any firm contracted capacity for DTE Electric or other utilities.

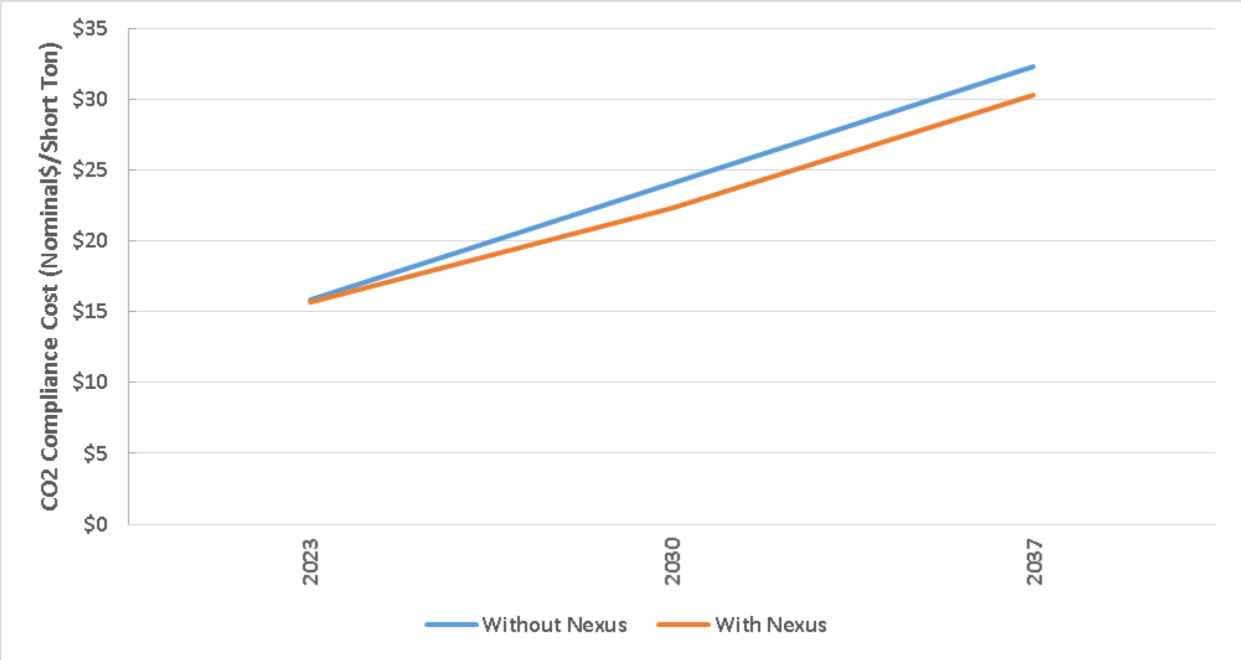
Electric utilities are expected to have reduced power production costs which drive the change in wholesale power prices. The largest change is expected for gas-fired generation facilities which would experience roughly a $1.2 billion savings in gas fuel purchases with NEXUS.

4.2.1 Impacts of NEXUS on Michigan CPP Compliance Costs

The decline in natural gas prices available to generation resources in Michigan due to the NEXUS Pipeline could also enable a reduction in CO2 compliance costs for compliance with EPA's Final CPP Rule of August 2015. Overall, the compliance cost, as reflected in the shadow price of a compliance constraint is reduced as shown in Exhibit 4-5 below. Overall, this reflects a reduction of $1.35/Short Ton on average between IPM run years 2023 and 2037.

This benefit from reduced CPP compliance costs is already incorporated into the wholesale power prices described above. While the final form of the CPP compliance alternative for Michigan is not yet known, regardless of the approach, lower natural gas fuel pricing will provide some benefit as compliance costs will be reduced overall.

Exhibit 4-5: Impact of NEXUS Pipeline on Michigan State CPP Compliance Costs (Nominal $/Short Ton)



Source: ICF

4.3 Benefits to DTE Electric of Holding NEXUS Capacity

The benefits to DTE Electric of contracting for NEXUS Pipeline capacity are independent of the benefits to the Michigan energy markets tied to the construction of the pipeline itself. The reduction in natural gas prices, and the associated natural gas purchase cost savings accruing to Michigan natural gas consumers and wholesale power providers will occur if the NEXUS Pipeline is brought into service regardless of whether or not DTE Electric holds capacity on the NEXUS Pipeline.

There are two primary benefits associated with the DTE Electric contract for NEXUS capacity. Contracting for capacity on the NEXUS Pipeline increases the likelihood that the pipeline project will be developed and reduces DTE Electric natural gas supply expenditures. These benefits are described below.

4.3.1 Impact on the Likelihood that NEXUS Pipeline Will Proceed

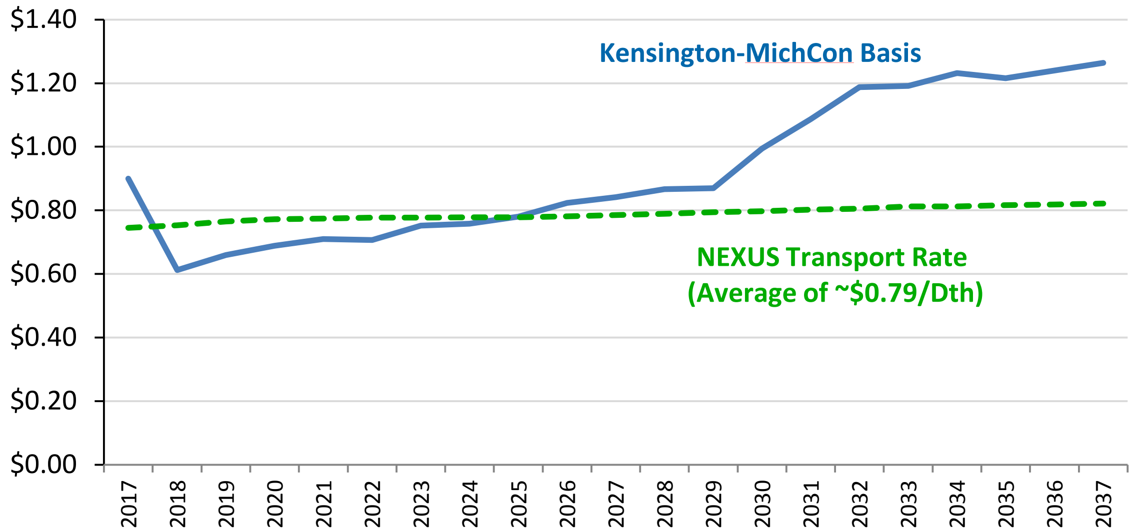
While DTE Electric does not need to hold capacity on the NEXUS Pipeline in order to benefit from the reduction in natural gas prices in Michigan associated with the construction of the pipeline, the NEXUS Pipeline has not yet filed a full application for project approval with FERC, and development of the NEXUS Pipeline remains uncertain. Holding capacity on the pipeline increases the likelihood that the pipeline project will be developed, and helps to ensure that the benefits associated with pipeline construction will be realized.

Based on preliminary FERC filings by the Pipeline, the full capacity of the pipeline has not yet been fully contracted. While it is difficult to determine whether a specific commitment for pipeline capacity is necessary to ensure construction of the project, the pipeline will not be developed without contracts supporting a significant percentage of the proposed capacity. The DTE Electric commitment represents between 5 and 10 percent of the contracted capacity on the pipeline, which is important in ensuring that the project continues to be developed.

4.3.2 Contracting for Capacity Reduces DTE Electric Natural Gas Supply Expenditures

ICF is projecting that over the life of the DTE Electric contract for NEXUS Pipeline capacity, DTE Electric will be able to reduce the total cost of natural gas purchased by the company and delivered using the contracted pipeline capacity. Exhibit 4-4 shows the price difference (also referred to as the “basis spread”) between Kensington and the MichCon Citygate, and the estimated transportation cost for firm capacity on NEXUS. The NEXUS rate is based on an assumed capacity charge of $0.695 per Dth plus fuel charges of 1.9% of the projected Kensington price, and averages $0.79 per Dth through 2037.

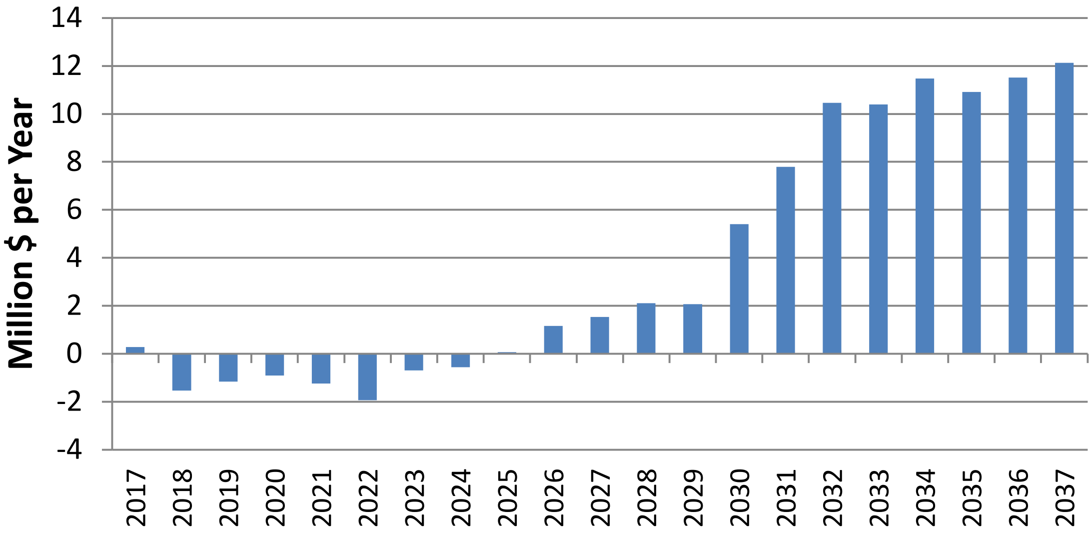
Exhibit 4-6: Kensington-MichCon Basis versus NEXUS Transport Cost (Nominal $/MMBtu)



Source: ICF projections

Compared to the projected basis from Kensington and MichCon, the firm transport rate (plus fuel) on NEXUS averages $0.13/MMBtu lower from November 2017 through October 2037. Because cost of gas delivered via NEXUS is, on average, lower than the MichCon Citygate price, holding NEXUS capacity reduced DTE Electrics gas expenditures beyond the savings attributable to the decline in the Citygate price. At these contract volumes, the reduction in DTE Electric’s natural gas purchase costs attributable to holding the NEXUS Pipeline capacity total $79 million for the 20 year contract period from 2018 through 2037 (Exhibit 4-7). Discounted to the start of 2018, the NPV of the natural gas purchase cost savings would be approximately $22 million.

Exhibit 4-7: Reduction in DTE Electric Natural Gas Expenditure from Contracting NEXUS Capacity (Nominal $)



Source: ICF projections

4.4 Overall Cost Savings Associated with the NEXUS Pipeline

Exhibit 4-8 summarizes the overall cost saving associated with the additional of NEXUS Pipeline. Residential, commercial, and industrial natural gas expenditures (Line 1 of Exhibit 4-8) are reduced by $1.9 billion.

Natural gas costs accruing to power producers (line 2) are reduced by $1.2 billion. This $1.2 billion would be a direct savings to Michigan ratepayers through utility based recovery of power supply costs (i.e., utilities recover their costs of producing power). In addition, given that gas generation is increasing, other higher cost resources would be displaced, further adding to production cost savings to the utilities and ratepayers. The full impact to utility consumers has not been calculated herein, rather, the $1.2 billion in gas fuel savings is conservatively used as a floor of what the overall consumer savings would be.

Wholesale power markets are expected to experience overall lower wholesale energy transaction costs in the Michigan (MISO Zone 7) due to lower gas prices as well. The power market savings are estimated to be about $3.2 billion between 2018 and 2037. A certain share of this amount would also directly impact ratepayers exercising retail choice options. While these costs do not fully accrue to residential ratepayers in Michigan, they are relevant to the overall market given that a number of industrial and commercial customers exercise retail choice and hence would feel the full effect of the impact to wholesale power prices. Currently, there is a 10% cap on customers for electric choice.

Exhibit 4-8: Cost Savings Associated with NEXUS Pipeline (Billions of Dollars)

	Billions of Nominal Dollars, 2018 through 2037	Net Present Value of Savings, in Billions of Dollars[1]
1) Reduction in Natural Gas Expenditures by Michigan Residential, Commercial, and Industrial Consumers (based on weighted average cost of gas supply portfolio)	**$1.90**	**$0.80**
2) Reduction in Natural Gas Expenditures by Michigan Power Generators (based on gas consumed by power generators in Michigan and reduction in MichCon Citygate price)	**$1.20**	**$0.50**
3) Michigan Electricity Market Wholesale Energy Transaction Cost Savings[2]	***$3.20***	***$1.40***
4) Total Impact of Nexus Pipeline on Michigan Gas and Power Consumers [1] + [2][3]	**$3.10**	**$1.30**

1. All net present value savings are discounted to the start of 2018 using a discount rate of 7.1%. *Source: ICF*
2. Wholesale power prices will be impacted in a broader area than Michigan alone, the value shown here reflects Michigan Zone 7 savings only.
3. Gas production cost savings are used as a proxy for the retail impact. To estimate the retail impact more precisely, additional analysis would be required.

The total impact of the NEXUS Pipeline on Michigan consumers including gas consumers and electric rate payers is the sum of the natural gas cost reductions to non-power consumers ($1.9 billion), plus the reduction production costs (conservatively valued at the change in gas fuel costs of $1.2 billion), plus the incremental cost savings to electric choice customers (excluded from this estimation). The net impact of the NEXUS Pipeline on Michigan natural gas and wholesale power costs in the absence of the incremental savings to the current electric choice customers is expected to be about $3.1 billion, with a net present value of $1.3 billion over the 20 year life of the DTE Electric contract for NEXUS capacity, if the NEXUS Pipeline is built.

In addition to the benefits described above for Michigan customers, DTE Electric ratepayers should also achieve additional gas purchase cost savings of about $79 million, with a net present value of $22 million if DTE Electric contracts for NEXUS capacity. These cost savings, shown in Exhibit 4-9, are due to the ability provided by the NEXUS pipeline contract to purchase natural gas at the lower supply basin prices, rather than at Michigan market prices.

Exhibit 4-9: Incremental Benefit to DTE of Firm Pipeline Capacity Purchase (Billions of Dollars)

	Billions of Nominal Dollars, 2018 through 2037	Net Present Value of Savings, in Billions of Dollars[1]
Impact of Holding NEXUS Capacity on DTE Electric Natural Gas Expenditures	**$0.08**	**$0.02**

Appendix A: ICF's Natural Gas Market Analysis Methodology

A.1 Gas Market Model (GMM)

ICF's Gas Market Model (GMM) is an internationally recognized modeling and market analysis system for the North American gas market. The GMM was developed in the mid-1990s to provide forecasts of the U.S. and Canada natural gas market under different assumptions. In its infancy, the model was used to simulate changes in the gas market that occur when major new sources of gas supply are delivered into the marketplace. Subsequently, GMM has been used to complete strategic planning studies for many private sector companies. The different studies include:

- Analyses of different pipeline expansions
- Measuring the impact of gas-fired power generation growth
- Assessing the impact of low and high gas supply
- Assessing the impact of different regulatory environments

In addition to its use for strategic planning studies, the model has been widely used by a number of institutional clients and advisory councils, including Interstate Natural Gas Association of America (INGAA), which has relied on the GMM for multiple studies over the past ten years. The model was also the primary tool used to complete the widely referenced study on the North American Gas market for the National Petroleum Council in 2003, and the 2010 Natural Gas Market Review for the Ontario Energy Board.

GMM is a full supply/demand equilibrium model of the North American gas market. The model solves for monthly natural gas prices throughout North America, given different supply/demand conditions, the assumptions for which are specified by scenario. Overall, the model solves for monthly market clearing prices by considering the interaction between supply and demand curves at each of the model's nodes. On the supply-side of the equation, prices are determined by production and storage price curves that reflect prices as a function of production and storage utilization (Figure A-1) Prices are also influenced by "pipeline discount" curves, which reflect the change in basis or the marginal value of gas transmission as a function of load factor. On the demand-side of the equation, prices are represented by a curve that captures the fuel-switching behavior of end-users at different price levels. The model balances supply and demand at all nodes in the model at the market clearing prices determined by the shape of the supply and curves. Unlike other commercially available models for the gas industry, ICF does significant backcasting (calibration) of the model's curves and relationships on a monthly basis to make sure that the model reliably reflects historical gas market behavior, instilling confidence in the projected results.

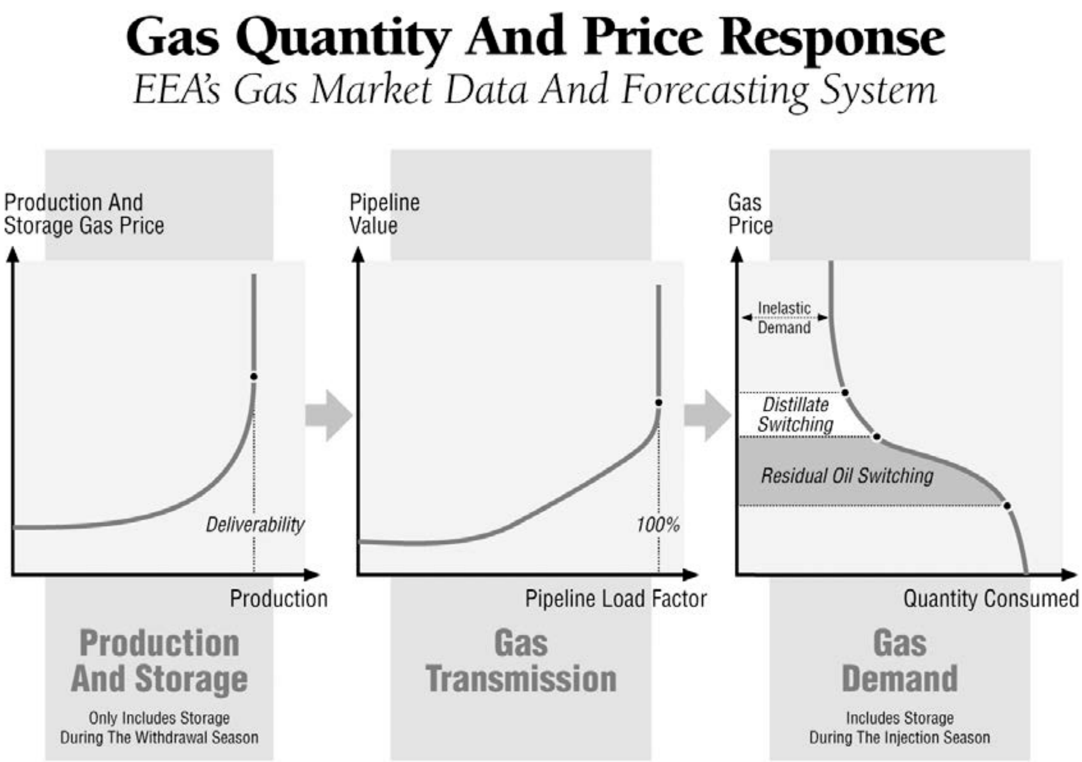


Figure A-1: ICF's Gas Market Data and Forecasting System

There are nine different components of GMM, as shown in Figure A-2. The user specifies input for the model in the "drivers" spreadsheet. The user provides assumptions for weather, economic growth, oil prices, and gas supply deliverability, among other variables. ICF's market reconnaissance keeps the model up to date with generating capacity, storage and pipeline expansions, and the impact of regulatory changes in gas transmission. This is important to maintaining model credibility and confidence of results.

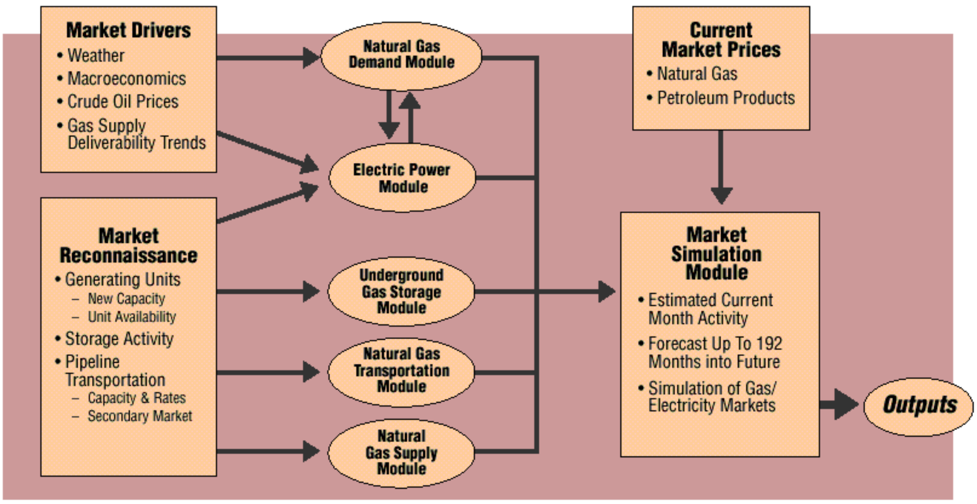


Figure A-2: GMM Components

The first model routine solves for gas demand across different sectors, given economic growth, weather, and the level of price competition between gas and oil. The second model routine solves the power generation dispatch on a regional basis to determine the amount of gas used in power generation, which is allocated along with end-use gas demand to model nodes. The model nodes are tied together by a series of network links in the gas transportation module. The structure of the transmission network is shown in Figure A-3, and the detailed structure in the Marcellus/Utica area is show in Figure A-4. The gas supply component of the model solves for node-level natural gas deliverability or supply capability, including LNG import and export levels. The last routine in the model solves for gas storage injections and withdrawals at different gas prices. The components of supply (i.e., gas deliverability, storage withdrawals, supplemental gas, LNG imports, and Mexican imports) are balanced against demand (i.e., end-use demand, power generation gas demand, LNG exports, and Mexican exports) at each of the nodes and gas prices are solved for in the market simulation module.

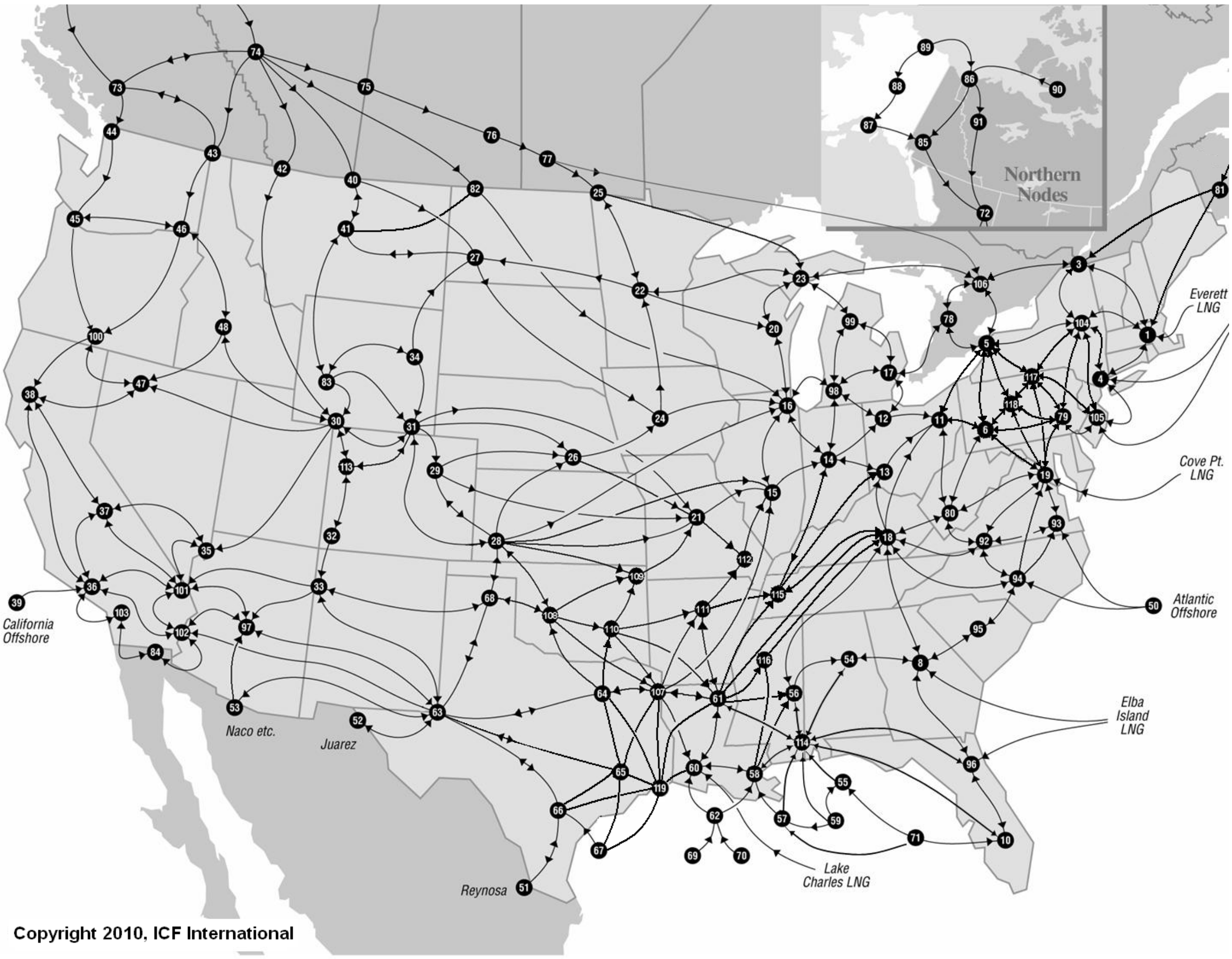
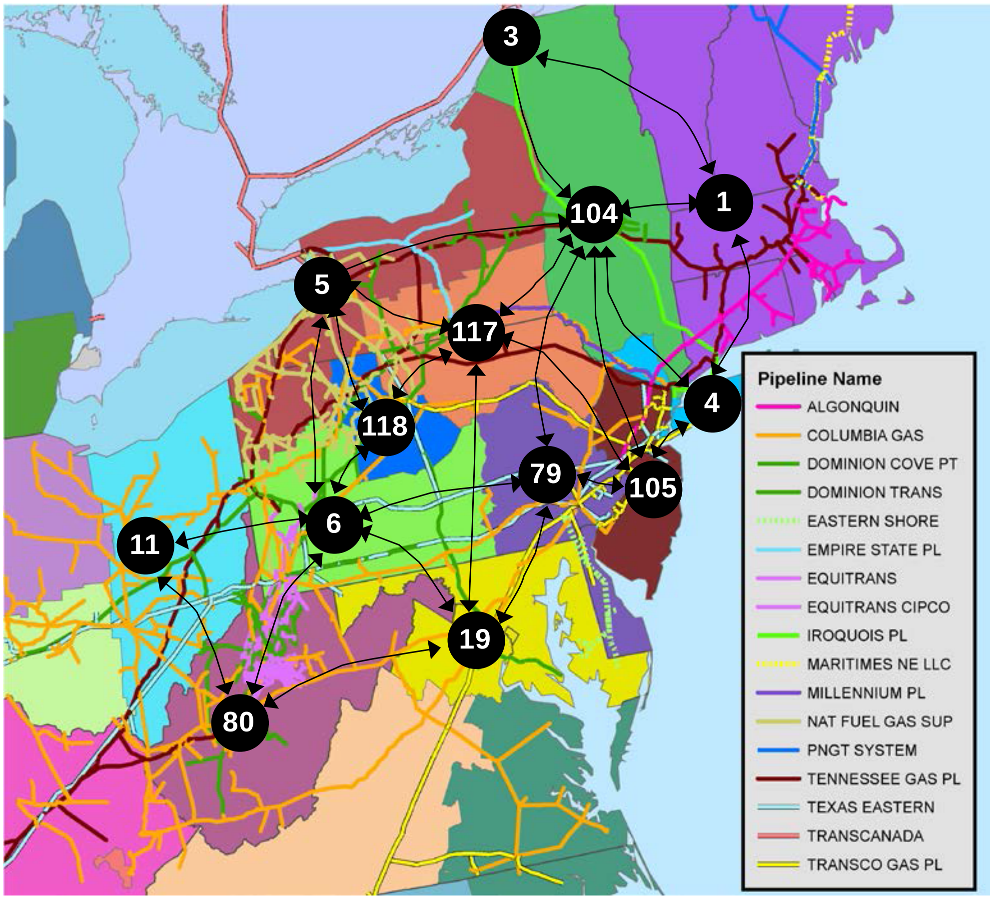


Figure A-3: GMM Transmission Network

Figure A-4: GMM Transmission Network in the Marcellus/Utica Basins



A.2 ICF Natural Gas Supply Assessment Methodology

ICF's Natural Gas Supply Assessment Methodology (ISAM) covers the Continental United States, Alaska and Canada. The Continental United States is represented in 28 onshore regions (see figure A-5) and 11 offshore regions.

Figure A-5: NPC Continental US Supply Regions

Alaska is divided into seven regions and Canada is divided into ten regions. All regions are further broken out into subregions or "intervals." They represent some combination of drilling depths, water depth, or geographic areas.

Resources are divided into three general categories: new fields/new pools, field appreciation, and unconventional gas. The methodology for resource characterization and economic evaluation differs for each.

New Fields

New discoveries are characterized by size class. For the United States, the number of fields within a size class is broken down into oil fields, high permeability gas fields, and low permeability gas fields based on the expected occurrence of each type of field within the region and interval being modeled. The fields are characterized further as having a hydrocarbon make-up containing a certain percent each of crude oil, dry natural gas, and natural gas liquids. In Canada, fields are oil, sweet nonassociated gas, or sour nonassociated gas.

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The methodology uses a modified "Arps-Roberts" equation to estimate the rate at which new fields are discovered. The fundamental theory behind the find-rate methodology is that the probability of finding a field is proportional to the field's size as measured by its areal extent, which is highly correlated to the field's level of reserves. For this reason, larger fields tend to be found earlier in the discovery process than smaller fields. The new equation developed by ICF accurately tracks discovery rates for mid- to small-size fields. Since these are the only fields left to be discovered in many mature areas, the more accurate find-rate representation is an important component in analyzing the economics of exploration activity in these areas.

The find-rate equations are used in the model to predict the number of fields of a certain size that will be discovered after a given number of exploratory wells have been drilled. There are separate equations for each field-size class (e.g., size class 6 is between one and two million barrels of oil equivalent) within each depth interval, within each region. The Continental US portion of the model alone has over 3,000 separate find-rate equations. This is a very fine level of detail given that actual annual new field discoveries have been below 600 fields in recent years.

An economic evaluation is made in the model each year for potential new field exploration programs using a standard discounted after-tax discounted cash flow (DCF) analysis. This DCF analysis takes into account how many fields of each type are expected to be found and economics of developing each. There are about 7,000 prototype field development plans in the model for the Continental US that include all capital and operating costs and production timing specifications built up from historical data. The economic decision to develop a field is made using "sunk cost" economics where the discovery cost are ignored and only time-forward development costs and production revenues are considered. However, the model's decision to begin an exploration program includes all exploration and development costs.

The results for new field exploration are reported in standard output tables that show the marginal economics (internal rate of return and resource cost) of exploration in each region and interval throughout the forecast. There are also outputs in Excel and Access format showing the number of fields being found, recoverable hydrocarbons discovered and recoverable hydrocarbons developed.

Unconventional Gas

The ICF assessment method for shale gas is a "bottom-up" approach that first generates estimates of unrisked and risked gas-in-place (GIP) from maps of depth, thickness, organic content, and thermal maturity. Then, ICF uses a different model to estimate well recoveries and production profiles. Unrisked GIP is the amount of original gas-in-place determined to be present based upon geological factors— without risk reductions. "Risked GIP" includes a factor to reduce the total gas volume on the basis of proximity to existing production and geologic factors such as net thickness (e.g., remote areas, thinner areas, and areas of high thermal maturity have higher risk). ICF calibrates expected well recoveries with specific geological settings to actual well recoveries by using a rigorous method of analysis of historical well data. In late 2011, ICF undertook an extensive analysis of Marcellus well recoveries and compared them with model results with good correlation. ICF confirmed that the model well recoveries are conservative. Additional analysis in 2012 also confirmed these results.

Major Unconventional Natural Gas Categories

Definition of Unconventional Gas: *Quantities of natural gas that occur in continuous, widespread accumulations in low quality reservoir rocks (including low permeability or tight gas, coalbed methane, and shale gas), that are produced through wellbores but require advanced technologies or procedures for economic production.*

Tight Gas is defined as natural gas from gas-bearing sandstones or carbonates with an *in situ* permeability (flow rate capability) to gas of less than 0.1 millidarcy. Many tight gas sands have *in situ* permeability as low as 0.001 millidarcy. Wells are typically vertical or directional and require artificial stimulation.

Coalbed Methane is defined as natural gas produced from coal seams. The coal acts as both the source and reservoir for the methane. Wells are typically vertical but can be horizontal. Some coals are wet and require water removal to produce the gas, while others are dry.

Shale Gas is defined as natural gas from shale formations. The shale acts as both the source and reservoir for the methane. Older shale gas wells were vertical while more recent wells are primarily horizontal with artificial stimulation. Only shale

Upstream Cost and Technology Factors

In ICF's methodology, supply technology advancements effects are represented in three categories:

- Improved exploratory success rates
- Cost reductions of platform, drilling, and other components
- Improved recovery per well

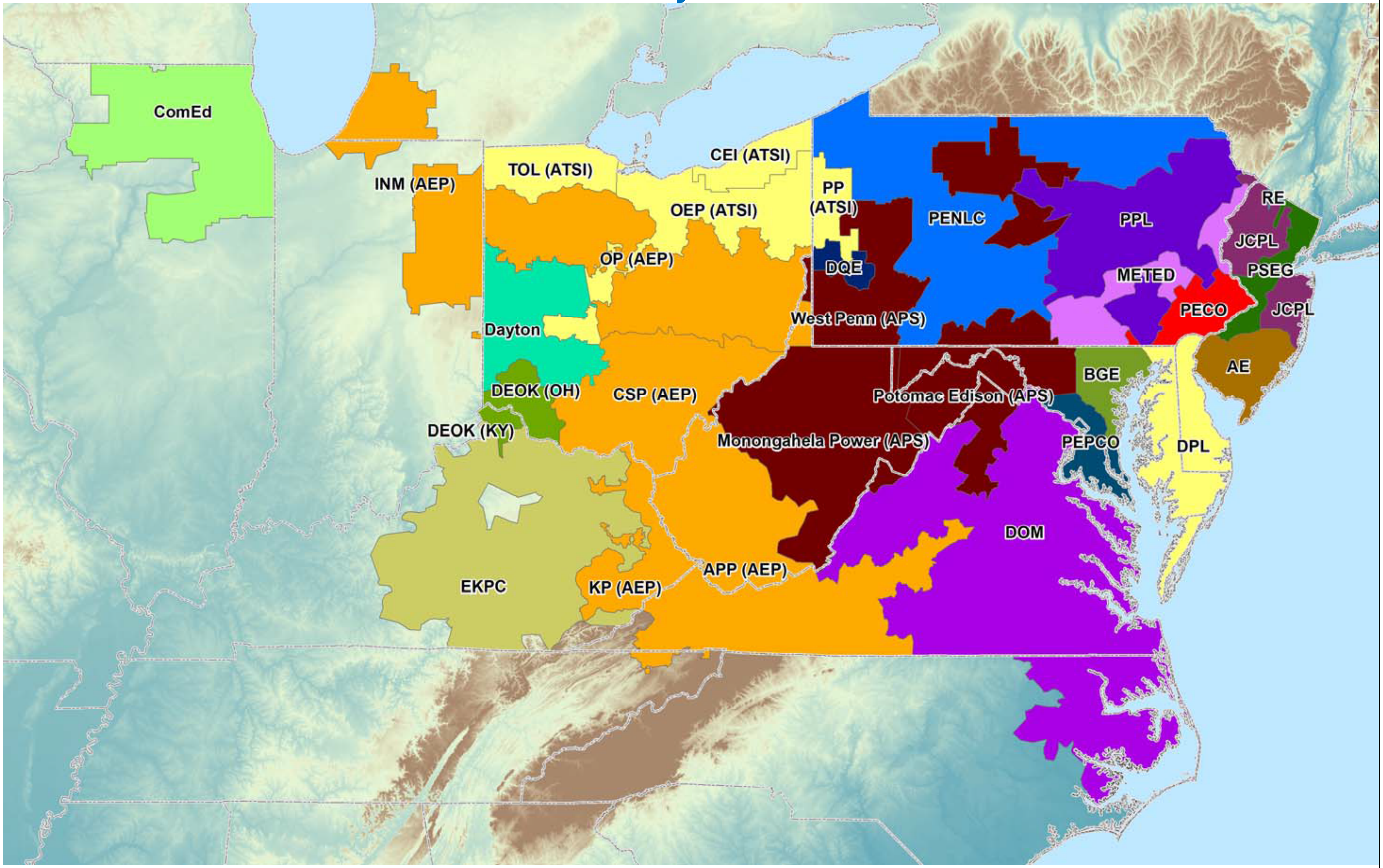
These factors are included in the model by region and type of gas and represent several dozen actual model parameters. ICF's database contains base year cost for wells, platforms, operations and maintenance, and other relevant cost items.

Appendix B: Proposed Pipeline Expansion Projects from Marcellus/Utica Basin

Natural Gas Pipeline Projects	Company	Product	Origin	Destination	Capacity (MMcfd)	In-Service Date	Status
Rose Lake Expansion Project	Tennessee Gas Pipeline	Natural Gas	Tioga, PA	Bradford, PA	230	Nov-14	In-Service
Mercer Expansion Project	National Fuel	Natural Gas	Washington, PA	Washington, PA	105	Nov-14	In-Service
TEAM 2014	Texas Eastern Transmission	Natural Gas	OH, PA, WV	PA, NY, NJ	600	Nov-14	In-Service
Northeast Connector Expansion	Williams Transco	Natural Gas	York, PA	Queens, NY	100	May-15	In-Service
Rockaway Lateral	Williams Transco	Natural Gas	Lower New Yok Bay, NY	Brooklyn NY	647	May-15	In-Service
Tygart Valley Pipeline	Crestwood Midstream	Natural Gas	Randolph, WV	Barbour, WV	200	Dec-12	In-Service
Seneca Lateral	Rockies Express Pipeline	Natural Gas	Noble, OH	Noble, OH	250	Jun-14	In-Service
West Side Expansion - Smithfield III	Columbia Gas Transmission	Natural Gas	Waynesburg, PA	Smithfield, WV	444	Nov-14	In-Service
Natrium to Market	Dominion Transmission	Natural Gas	Marshall, WV	Greene, PA	185	Oct-14	In-Service
Wright Interconnect Expansion	Iroquois Gas Transmission	Natural Gas	Scholarie, WV	Scholaries, NY	650	Mar-16	Under Construction
Southeast Mainline Reversal Ph. 1	ANR Pipeline	Natural Gas	Defiance, OH	Kentucky	1,250	Nov-14	In-Service
Southeast Mainline Reversal Ph. 2	ANR Pipeline	Natural Gas	Shelbyville, IN	Eunice, LA	600	Dec-15	Under Construction
Constitution	Williams/Cabot/Piedmont	Natural Gas	Susquehanna, PA	Scholaries, NY	650	Jun-16	Under Construction
Zone-3 East to West Project	Rockies Express Pipeline	Natural Gas	Monroe, OH	Moultrie, IL	1,800	Sep-15	In-Service
Virginia Southside Expansion	Williams Transco	Natural Gas	Pittsylvania, VA	Brunswick, VA	270	Sep-15	In-Service
Central Tioga Country	Empire Pipeline	Natural Gas	Tioga, PA	Tioga, PA	250	Nov-16	Announced
Ohio Pipeline Energy Network (OPEN)	Texas Eastern Transmission	Natural Gas	Columbiana, OH	Monroe, OH	550	Nov-15	Partial In-Service
Leidy Southeast	Williams Transco	Natural Gas	Leidy, PA	Choctaw, AL	525	Dec-15	Partial In-Service
Northern Access 2015	National Fuel	Natural Gas	Cattaraugus, NY	Cattaraugus, NY	140	Nov-15	Under Construction
West Side Expansion	National Fuel	Natural Gas	Washington, PA	Beaver, PA	95	Oct-15	Under Construction
Uniontown to CityGas	Texas Eastern Transmission	Natural Gas	Greene, PA	Grant, IN	425	Sep-15	In-Service
Broad Run Flexibility Project	Tennessee Gas Pipeline	Natural Gas	Broad Run Lateral, WV	Broad Run Lateral, WV	590	Nov-15	Under Construction
East Side Expansion	Columbia Gas Transmission	Natural Gas	Harford, MD	Orange, NY	312	Oct-15	Under Construction
Lebanon Lateral Reversal	ANR Pipeline	Natural Gas	Lebanon, OH	Shelbyville, IN (ANR Mainline)	350	Mar-14	In-Service
Ohio-Louisiana Project	Texas Eastern Transmission	Natural Gas	Lebanon, OH	Louisiana	760	Jun-16	FERC Approved
Clarington Project	Dominion Transmission	Natural Gas	Marshall, WV	Monroe, OH	250	Nov-16	FERC Approved
AIM Project	Algonquin Gas Transmission	Natural Gas	Rockland, NY	Norfolk, MA	342	Nov-16	Under Construction
NEXUS Gas Transmission	Spectra Energy	Natural Gas	Stark, OH	IN, MI, Ontario	1,500	Nov-17	FERC Pre-Filing
Leach Xpress	Columbia Gas Transmission	Natural Gas	Marshall, WV	Leach, KY	1,500	Nov-17	FERC Application
Rayne Xpress	Columbia Gas Transmission	Natural Gas	Leach, KY	Rayne, LA	1,500	Nov-17	FERC Application
Continent to Coast Expansion Project (C2C)	Portland Natural Gas Transmission	Natural Gas	Coos, NH	Cumberland, ME	350	Nov-16	Announced
South to North (SoNo)	Iroquois Gas Transmission	Natural Gas	Brookfield, CT	Waddington, NY	300	Dec-16	Announced
TGP 200 Line Looping	Tennessee Gas Pipeline	Natural Gas	Wright, NY	Mendon, MA	1,000	Nov-17	FERC Pre-Filing
Northern Supply Access	Texas Eastern Transmission	Natural Gas	Lebanon, OH	Texas (multiple delivery points)	580	Apr-17	FERC Approved
Rover Pipeline Ph. 1	Energy Transfer	Natural Gas	PA, WV, OH	Defiance, OH	2,200	Dec-16	FERC Application
Rover Pipeline Ph. 2	Energy Transfer	Natural Gas	Defiance, OH	Sarnia, ON	1,050	Jun-17	FERC Application
ANR East	ANR Pipeline	Natural Gas	Harison, OH	Defiance, OH	1,200	Nov-18	Announced
Atlantic Sunrise	Williams Transco	Natural Gas	PA	AL	1,700	Jul-17	FERC Application
Broad Run Expansion Project	Tennessee Gas Pipeline	Natural Gas	Broad Run Lateral, WV	Broad Run Lateral, WV	200	Nov-17	FERC Application
Gulf Markets Expansion Ph. 1	Texas Eastern Transmission	Natural Gas	Clarington, OH	Louisiana	350	Nov-16	FERC Application
Gulf Markets Expansion Ph. 2	Texas Eastern Transmission	Natural Gas	Clarington, OH	Louisiana	300	Aug-17	FERC Application
Atlantic Bridge	Algonquin Gas Transmission	Natural Gas	Bergen, NJ	Maritimes, CAN	150	Nov-17	Announced
Northeast Energy Direct (NED)	Tennessee Gas Pipeline	Natural Gas	Wright, NY	Dracut, MA	2,200	Nov-18	FERC Pre-Filing

PJM Load Forecast Report

January 2016



Prepared by PJM Resource Adequacy Planning Department

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TERMS AND ABBREVIATIONS USED IN THIS REPORT

AE	Atlantic Electric zone (part of Pepco Holdings, Inc)
AEP	American Electric Power zone (incorporated 10/1/2004)
APP	Appalachian Power, sub-zone of AEP
APS	Allegheny Power zone (incorporated 4/1/2002)
ATSI	American Transmission Systems, Inc. zone (incorporated 6/1/2011)
Base Load	Average peak load on non-holiday weekdays with no heating or cooling load. Base load is insensitive to weather.
BGE	Baltimore Gas & Electric zone
CEI	Cleveland Electric Illuminating, sub-zone of ATSI
COMED	Commonwealth Edison zone (incorporated 5/1/2004)
Contractually Interruptible	Load Management from customers responding to direction from a control center
Cooling Load	The weather-sensitive portion of summer peak load
CSP	Columbus Southern Power, sub-zone of AEP
Direct Control	Load Management achieved directly by a signal from a control center
DAY	Dayton Power & Light zone (incorporated 10/1/2004)
DEOK	Duke Energy Ohio/Kentucky zone (incorporated 1/1/2012)
DLCO	Duquesne Lighting Company zone (incorporated 1/1/2005)
DOM	Dominion Virginia Power zone (incorporated 5/1/2005)
DPL	Delmarva Power & Light zone (part of Pepco Holdings, Inc)
EKPC	East Kentucky Power Cooperative (incorporated 6/1/2013)
FE-East	The combination of FirstEnergy's Jersey Central Power & Light, Metropolitan Edison, and Pennsylvania Electric zones (formerly GPU)
Heating Load	The weather-sensitive portion of winter peak load
INM	Indiana Michigan Power, sub-zone of AEP
JCPL	Jersey Central Power & Light zone
KP	Kentucky Power, sub-zone of AEP

METED	Metropolitan Edison zone
MP	Monongahela Power, sub-zone of APS
NERC	North American Electric Reliability Corporation
Net Energy	Net Energy for Load, measured as net generation of main generating units plus energy receipts minus energy deliveries
OEP	Ohio Edison, sub-zone of ATSI
OP	Ohio Power, sub-zone of AEP
PECO	PECO Energy zone
PED	Potomac Edison, sub-zone of APS
PEPCO	Potomac Electric Power zone (part of Pepco Holdings, Inc)
PL	PPL Electric Utilities, sub-zone of PLGroup
PLGroup/PLGRP	Pennsylvania Power & Light zone
PENLC	Pennsylvania Electric zone
PP	Pennsylvania Power, sub-zone of ATSI
PS	Public Service Electric & Gas zone
RECO	Rockland Electric (East) zone (incorporated 3/1/2002)
TOL	Toledo Edison, sub-zone of ATSI
UGI	UGI Utilities, sub-zone of PLGroup
Unrestricted Peak	Peak load prior to any reduction for load management, accelerated energy efficiency or voltage reduction.
WP	West Penn Power, sub-zone of APS
Zone	Areas within the PJM Control Area, as defined in the PJM Reliability Assurance Agreement

2016 PJM LOAD FORECAST REPORT

EXECUTIVE SUMMARY

- This report presents an independent load forecast prepared by PJM staff.

- The report includes long-term forecasts of peak loads, net energy, load management and distributed solar generation for each PJM zone, region, locational deliverability area, and the total RTO.

- All load models were estimated with historical data from January 1998 through August 2015. The models were simulated with weather data from years 1994 through 2014, generating 273 scenarios. The economic forecast used was Moody's Analytics' October 2015 release. Equipment indexes reflect the 2015 update of Itron's end-use data, which is consistent with the Energy Information Administration's 2015 Annual Energy Outlook.

- Table B-7 has been revised to reflect the transition of Demand Resource options available under the Capacity Performance rules of the Reliability Pricing Model.

- Table B-8 has been modified; it now represents the amount of distributed solar generation subtracted from each forecast year. These values reflect the impact of historical distributed solar generation at peak as well as the forecasted amount of solar additions at peak in each forecast year. **Distributed solar generation forecast values have already been subtracted from all forecast tables in the report.**

- With the adoption of a new load forecast model, PJM has reverted to publishing only one set of E-Tables (net energy).

- Since the 2015 report, PJM has significantly revised its load forecast model. The treatment of weather has been restructured to provide more variable load response to weather across a wide range of conditions. Three variables (cooling, heating, and other) were added to account for trends in equipment/appliance saturation and efficiency, and distributed solar generation is now reflected in the historical load data used to estimate the models, with a separately-derived solar forecast used to adjust load forecasts. Detailed information on the development of the distributed solar generation forecast can be found at: http://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process.aspx.

- The economic regions used for each zone have been revised to be consistent with the revised definitions of metropolitan areas of the U.S. Office of Management and Budget. An exception is DOM zone, for which economic data for the Commonwealth of Virginia is now used. Weather station mixtures have been revised for AEP, EKPC, and PL zones.

- PJM has also significantly revised its process for developing the weather-normalized peaks that appear in the report. The new process involves estimating each zone's load and weather relationship for each season and evaluating that relationship at typical peak day weather conditions.

- The forecasts of the following zones have been adjusted to account for large, unanticipated load changes (see Table B-9 for details):
  - The forecast of the APS zone has been adjusted to account for accelerating load related to natural gas processing plants, adding 120-280 MW from 2016 through 2020 before declining to 200 MW in 2030.
  - The forecast of the DOM zone has been adjusted to account for substantial on-going growth in data center construction, which adds 240-1,050 MW to the summer peak beginning in 2016.

- The PJM RTO weather-normalized summer peak for 2015 was 150,295 MW (using the new normalization method). The projection for the 2016 PJM RTO summer peak is 152,131 MW, an increase of 1,836 MW, or 1.2%, from the 2015 normalized peak.

- Summer peak load growth for the PJM RTO is projected to average 0.6% per year over the next 10 years, and 0.6% over the next 15 years. The PJM RTO summer peak is forecasted to be 161,891 MW in 2026, a 10-year increase of 9,760 MW, and reaches 167,469 MW in 2031, a 15-year increase of 15,338 MW. Annualized 10-year growth rates for individual zones range from -0.1% to 1.2%.

- Winter peak load growth for PJM RTO is projected to average 0.8% per year over the next 10-year period, and 0.8% over the next 15-years. The PJM RTO winter peak load in 2025/26 is forecasted to be 140,912 MW, a 10-year increase of 10,669 MW, and reaches 146,225 MW in 2030/31, a 15-year increase of 15,982 MW. Annualized 10-year growth rates for individual zones range from 0% to 1.6%.

- Compared to the 2015 Load Report, the 2016 PJM RTO summer peak forecast shows the following changes for three years of interest:
  - The next delivery year – 2016 -5,781 MW (-3.7%)
  - The next RPM auction year – 2019 -5,660 MW (-3.5%)
  - The next RTEP study year – 2021 -8,406 MW (-5.1%)

NOTE:
Unless noted otherwise, all peak and energy values are non-coincident, unrestricted peaks, which represent the peak load or net energy after reductions for distributed solar generation and prior to reductions for load management impacts.
All compound growth rates are calculated from the first year of the forecast.

Summary Table

SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR PJM RTO AND SELECTED GEOGRAPHIC REGIONS

	METERED 2015	UNRESTRICTED 2015	NORMAL 2015		THIS YEAR 2016	RPM YEAR 2019	RTEP YEAR 2021
PJM RTO	143,446	143,496	150,295		152,131	156,958	157,358
				Growth Rate	1.2%		
Demand Resources					-8,777	-9,035	-3,424
PJM RTO - Restricted					143,354	147,923	153,934
PJM MID-ATLANTIC	54,889	54,889	56,495		57,174	58,464	58,310
				Growth Rate	1.2%		
Demand Resources					-3,556	-3,627	-1,347
MID-ATL - Restricted					53,618	54,837	56,963
EASTERN MID-ATLANTIC	30,240	30,240	31,095		31,278	31,924	31,709
				Growth Rate	0.6%		
Demand Resources					-1,289	-1,315	-494
EMAAC - Restricted					29,989	30,609	31,215
SOUTHERN MID-ATLANTIC	12,419	12,419	12,810		13,393	13,624	13,652
				Growth Rate	4.6%		
Demand Resources					-1,130	-1,149	-425
SWMAAC - Restricted					12,263	12,475	13,227

Note:
Normal 2015 and all forecast values are non-coincident as estimated by PJM staff.
Except as noted, all values reflect the membership of the PJM RTO as of June 1, 2015.

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December 2015

Adam Ozimek, 610-235-5127

Summary of the December 2015 U.S. macro forecast

The U.S. economy performed well in 2015, and 2016 should be even better. The economy is on track to return to full employment by midyear. It will have been almost a decade since the economy was last operating at full tilt.
Full employment is consistent with a 5% unemployment rate, which has already been achieved, and a 9% underemployment rate. Underemployment includes the unemployed, part-timers who want more hours, and potential workers that have stepped out of the workforce and thus are not counted as unemployed but say they want a job. This is the so-called U-6 unemployment rate, which currently stands at 9.8%. On a full-time equivalent basis—translating the part-timers into full-timers—it is about 9.6%.

At the current pace of job growth of more than 200,000 per month, if sustained, the economy will be back to full employment by next summer. To be even more precise, given that the working-age population is growing by only 100,000 per month, the underemployment or U-6 unemployment rate should stand at 9% by August. There is clearly much uncertainty around this estimate, but there is little doubt that full employment is approaching fast.

Job machine

Businesses are adding jobs at a consistent and prodigious rate. Payrolls will expand by almost 3 million in 2015, about the same as the year before and the year before that. The last time job growth was as consistently strong was during the technology boom of the late 1990s.

The oil price collapse and resulting rationalization in the energy industry, and the stronger U.S. dollar and weakening in trade-sensitive manufacturing have slowed job growth a notch in recent months. But these constraints should fade by the spring. Moreover, job creation in the rest of the economy shows no signs of slowing.

Most encouraging is that job openings are about as plentiful as they have ever been. There are now less than three underemployed for every open job position.

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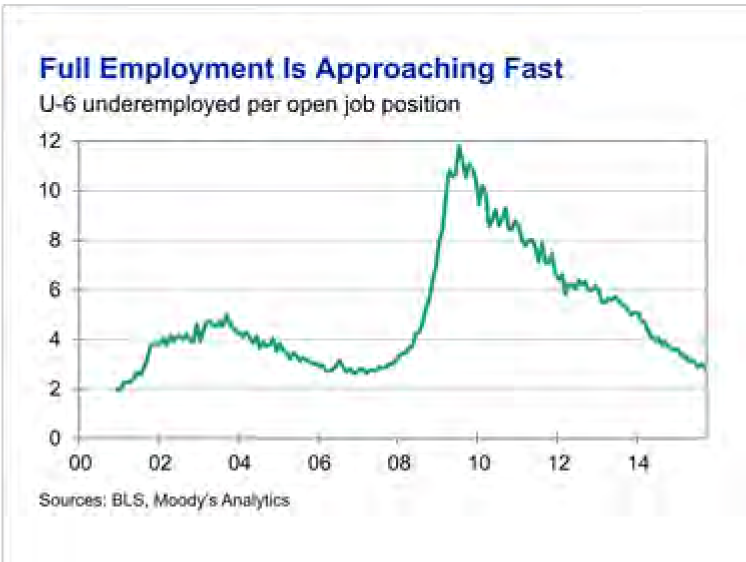

For context, at the worst of the recession, there was closer to 11 underemployed for each open position. Openings are widespread across most industries, but particularly in healthcare and professional services—two industries adding aggressively to their roles. Layoffs also remain extraordinarily low, with nearly record low numbers filing for unemployment insurance.

Wage resurgence

The tightening job market is evident from the recent firming in wage growth. According to the Bureau of Labor Statistics, average hourly earnings and wages as measured by the employment cost index have picked up meaningfully over the past year. After abstracting from the short-term ups and downs in these measures, wage growth is up nearly half a percentage point over the past year, well over the near 2% year-over-year growth that had prevailed since the recession.

Wage growth is even stronger than indicated by the BLS wage data. The BLS calculates wages based on reports from establishments that average pay across all their employees. Measured wage growth is being depressed as many lower-paid millennials are coming into the workforce, while higher-paid boomers are leaving it. The tighter labor market also means that those now finding jobs are likely less productive and thus lower-paid.

The importance of these worker-mix effects is evident from wage data constructed by Moody's Analytics based on payroll records maintained by human resource company ADP. The ADP data are derived by tracking the wages of individuals and are thus *not* impacted by the changing mix of workers in establishments. According to ADP, year-over-year wage growth for individuals is just more than 4%. Like the BLS data, ADP measured wage growth has accelerated by about half a percentage point over the past year.

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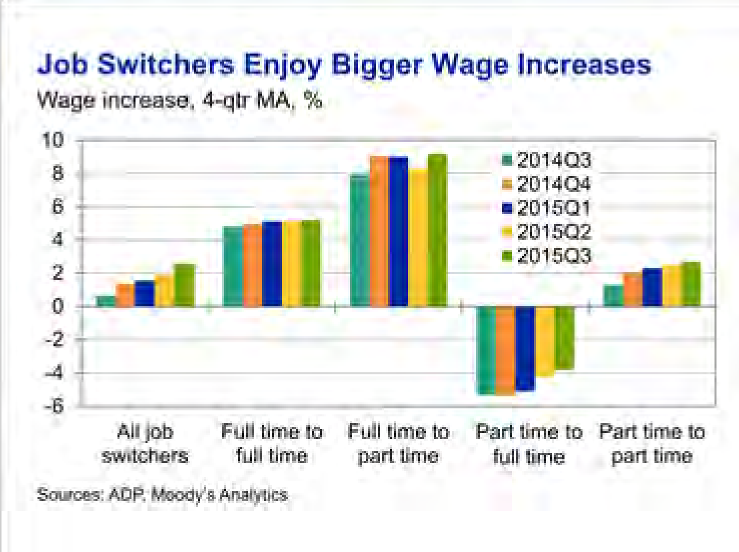
A positive near-term leading indicator of future wage growth in the ADP data is the pickup in wages paid to workers switching jobs. Across all switchers, pay increases have risen substantially over the past year.



Part-timers switching to either another part-time job or a full-time job enjoyed the biggest improvement. Switcher wages have accelerated across all but the energy industry and are up most in the construction trades and in healthcare. All age groups are enjoying increased switcher wages, but those in their prime working years of 35 to 54 have seen the largest acceleration. Switcher wages are up in all parts of the country, but most in the South and Midwest.

Wage risks

Wage growth is expected to accelerate substantially as the economy attains full employment. It may take a while, but wages are ultimately expected to reach a 3.5% growth rate. This is equal to the sum of inflation, which is expected to be near the Federal Reserve's 2% target, and 1.5% trend labor productivity growth. At this pace of growth, labor's share of national income will stabilize; labor's share has been shrinking more or less since the early 1980s.

There are both downside and upside risks to this outlook. On the downside is persistently weak productivity growth, which has been well below 1% per annum in recent years. Productivity is expected to pick up as businesses refocus on it. With labor costs so low since the recession, businesses have felt little pressure to invest in labor-saving technologies. This should change as businesses realize that their labor costs are rising with the tightening job market, but this is still a forecast.

On the upside is the likelihood that the job market will overshoot full employment. By the end of 2016, it will be clear that the economy's biggest problem is not unemployment, but a lack of qualified labor. Businesses in a rising number of industries will be in bidding wars for workers. According to

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homebuilders, this is already an issue in the construction trades, and manufacturers are also complaining they cannot find the highly skilled workers they need.

Rate normalization

Firming wage growth is the signal that the Federal Reserve has needed to begin normalizing interest rates. Policymakers indicate that the coming rate hikes will be gradual, with the funds rate ending 2016 at just more than 1%. This is a reasonable forecast, given that inflation remains well below the Fed's target, and the Fed's desire to err on the side of too strong an economy rather than a struggling one. The Fed desperately wants to avoid backtracking on the rate hikes or, even worse, having to resume quantitative easing or adopting other nontraditional policies.

Policymakers also rightly want to see what impact the rate hikes will have on broader financial market conditions. The stock market appears vulnerable, given its currently high valuation; an even stronger U.S. dollar seems likely; and credit spreads have the potential to significantly gap out, particularly for below-investment-grade corporate bonds. The seeming lack of transactional liquidity in markets could also exacerbate the volatility in all markets.

Financial pressures on already-fragile emerging markets could also intensify. Most vulnerable are countries that rely heavily on capital inflows and whose nonfinancial businesses have issued debt in dollars.

These include Turkey, South Africa, and a number of countries in Latin America and Southeast Asia. Growth in the EMs slowed sharply this past year, and the best that can be expected in the coming year is that they stabilize.

R* equilibrium

Just where the rate hikes end depends on the equilibrium funds rate, or R*—that funds rate consistent with an economy operating at its potential and inflation at the Fed's 2% target. There is a general consensus that R* has fallen since the Great Recession, but there is little consensus regarding by how much. The Fed's long-run forecast of the funds rate would suggest that the equilibrium funds rate is approximately 3.5%. This is equal to the sum of the Fed's 2% inflation target, the economy's potential growth rate, and the impact of various economic "headwinds."

Although not well-defined, the most significant headwind is the higher required capitalization and liquidity of the banking system post-crisis.

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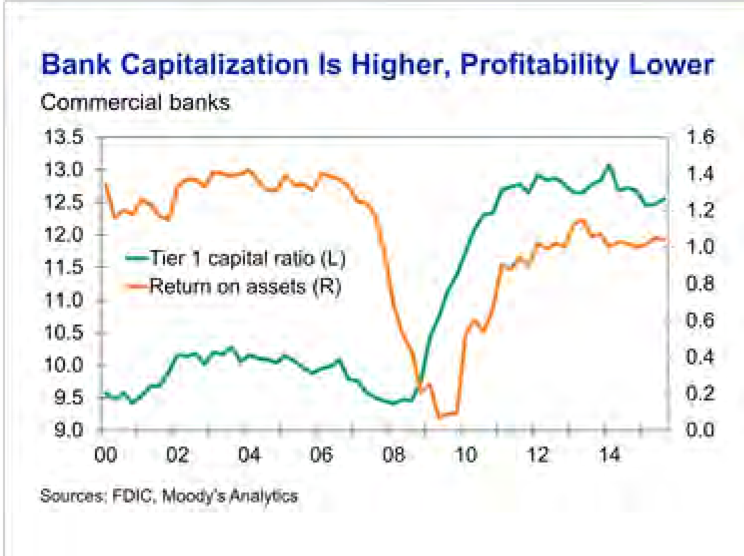

If regulators require that banks must hold more capital and be more liquid, then the banks' return on equity and assets will be lower. Thus for the system to extend the same amount of credit to the economy at the same lending rates, the system's cost of funds needs to fall by a like amount as its returns. That is, banks' lending margins—loan rates less cost of funds—must be maintained. This can be achieved if the Fed adopts a lower R*, and thus lower banks' cost of funds.
Like the Fed, we also estimate R* to be 3.5%, equal to 2% inflation, plus 2.2% potential real GDP growth, less 0.7% to account for the economic headwinds. The actual federal funds rate is expected to reach our 3.5% R* by spring 2018.

Rate risks

The Fed's path to R* is rife with risk. The equilibrium funds rate could be much lower than we are estimating, either because potential growth is lower or the headwinds are blowing harder. Financial markets seemingly believe this, as the futures market for fed funds puts the funds rate at closer to 2% by early 2018. However, there is also the risk that the economy will overshoot full employment, generating significant wage and prices pressures and forcing the Fed to ultimately play catch-up in raising rates. Indeed, the more gradual the rate hikes are in 2016, the more likely the Fed will have to increase rates more aggressively in 2017-2018 to forestall an overheating economy.

Certainly a lot could go wrong between now and 2018. But that should be a worry for another day. We should enjoy 2016 and a full-employment economy.

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Risks to the U.S. outlook

If the Fed jumps the gun and is forced to reverse course, quantitative easing would be restarted and negative interest rates would be possible. There are other options. Former Fed Chairman Ben Bernanke recounts in his new book some of the policies the Fed considered but did not implement during the Great Recession. They include negative interest rates, funding for lending, raising the inflation target, and pegging interest rates on securities with maturities of two years or less. The latter would be a commitment to keep rates low for at least two years, but the balance sheet would increase substantially. Nominal GDP targeting would be a radical option. The options Bernanke discussed could be the playbook if the Fed has to quickly reverse course.

Softer global demand, particularly in China and Europe, will hurt domestic exports and could cause GDP growth to fall short of expectations should the situation deteriorate further. The slowdown in China's economy is weighing heavily on the emerging economies in Asia and Latin America; this in turn has led to steep corrections in international equity markets. Further, Chinese policymakers could fumble in their efforts to try and stimulate growth, leading to further selloffs in China's equity markets. Slower global growth will hurt Midwest factories and coastal shipping hubs and is already subtracting from U.S. output growth. The main risk is that weakness will persist for longer than anticipated.

The weakness in global demand for U.S. exports will be aggravated by a stronger U.S. dollar. Trade data have been soft in recent months as the rising greenback has squeezed the market share of domestic firms. The impact has been most apparent in low-value-added industries that already struggle with fierce international competition. The widening divergence between U.S. monetary policy and monetary policy in Europe and Asia could cause the greenback to strengthen more than expected. The baseline forecast already assumes that the dollar will appreciate relative to the euro and the yen, as central bankers in these regions have initiated large-scale quantitative easing programs that will weaken their currencies. If foreign policymakers adopt even more expansionary policies, or if U.S. rates rise faster than expected, the dollar will push beyond the baseline forecast, further widening the trade deficit and causing GDP to fall below expectations.

Global tensions pose an indirect threat to the U.S. economy through the channels of global trade, consumer sentiment and financial markets. The conflict between Ukraine and Russia has led to a standoff between Russia and the West. With no resolution in sight, sanctions will likely prevail through next year and could push Russia deeper into recession. The consequences of the sanctions are disruptive for the euro zone economy, especially Germany, and could derail the euro zone's fragile recovery.

Conflicts in Iraq and Syria threaten to further destabilize the region. While the war against the Islamic State has been confined to Iraq and Syria, it could spread to

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other Middle Eastern countries, risking increased intervention by the West. The worst-case scenario involves escalated tensions in the region that could cause not only a spike in oil prices but also greater turmoil in global financial markets, leading to a drop in trade and slower global growth. Furthermore, instability in the region has triggered an exodus of refugees from Syria. The wave of migrants puts the EU's immigration system under tremendous stress as EU members struggle to establish a system to relocate refugees from overburdened countries.

Output growth will suffer if the U.S. dollar strengthens faster than expected. The currency will appreciate relative to the euro and the yen as monetary actions in the U.S., Europe and Japan are expected to diverge further and spreads between policy rates widen. A stronger dollar will be a net negative for the U.S. Exports will slow further and imports will rise rapidly, trends already evident in the U.S. trade deficit widening to $43.9 billion in October.

Further, the relationship is nonlinear, with the dollar subtracting an increasingly larger share of gross domestic output as it gains. Additionally, if foreign policymakers initiate even more expansive policies, or if U.S. rates rise faster than expected, the dollar will rise above the baseline forecast. In this event, U.S. exporters will be hit hard, imports will rise faster, and GDP will fall below expectations.

Summary of the forecast for PJM service territories

The PJM service territory covers all or parts of 13 states and the District of Columbia, accounting for more than 52 million people, or about a sixth of the U.S. population. The regional economies of the service territory include metro areas in the Midwest, South and Northeast and run the gamut from highly diversified, large economies such as Chicago, to small economies that depend heavily on one industry, such as Elkhart-Goshen IN.

Overall, education/healthcare remains the dominant industry in the service territory. Job growth for the industry has consistently outpaced the overall service territory economy and the gap has widened over the past year. This is attributable to the fading adjustment costs from the Affordable Care Act. Over the longer term, increasing demand from the aging population within the service territory and out will support job gains because of its greater utilization of healthcare services. Healthcare is an export industry to some economies in the service territory.

Consistent with the historical trend, education- and healthcare-related services will provide a significant share of new jobs in the forecast period.

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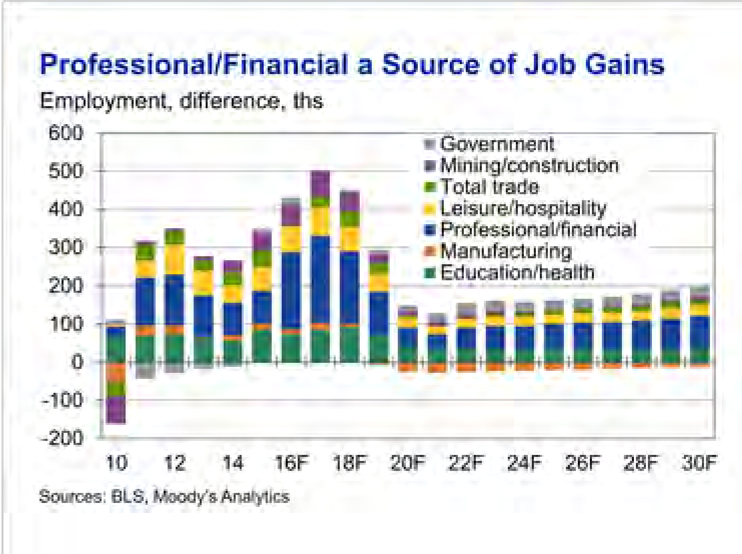

On average, the concentration of manufacturing in the service territory is roughly in line with the national average. However, approximately 60% of the metro areas, mainly smaller old-line manufacturing localities in the Northeast and Midwest, rely more heavily on industrial production for growth. The highest concentration of manufacturing is in Elkhart-Goshen IN, where nearly half of all jobs are in manufacturing. In contrast, the lowest concentration is in California-Lexington Park MD, where less than 1% of employment is in manufacturing.

The natural resources and mining industry represents a small portion of the service territory's economy, but has been a source of weakness recently. Low energy prices, a glut of natural gas, and heightened regulatory burdens on coal producers have left the industry shedding employment in 2015. The losses have been widespread in the service territory, with significant declines in Pennsylvania, Ohio, Virginia and West Virginia. Weakness is visible outside of manufacturing as the appreciation in the U.S. dollar, weakness in global demand, and a turn in the inventory cycle have weighed on output. Some of these weights will prove more persistent than others. The dollar will likely appreciate further as the Fed will be the first major central bank to begin tightening monetary policy while many others continue to ease.

While the public sector has a slightly smaller presence in the service territory than it does nationally, there is a greater concentration of federal government employment. This is largely due to the presence of the Washington-Arlington-Alexandria metro division, which contains the nation's capital and is home to one out of 10 federal government employees. With federal budget deficits under 3% and the deficit forecast over the next 10 years improving, the political pressure for austerity has declined. However, poor state fiscal positions in Illinois and Pennsylvania present a risk to the forecast for the service territory.

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Recent Performance

The service territory economy continues to improve. While the estimate of GDP growth from the third quarter of 2014 to the third quarter of 2015 is lower than expected, it is due to an upward revision to GDP in 2014.[1] Similarly, total employment growth of only 1.3% in the year to the third quarter of 2015 falls short of the forecast of 1.7%, however this is again due to a stronger than expected end to 2014. Total employment is essentially equal to the 19.6 million forecast.

Healthcare/education has tracked the forecast, as job growth has accelerated. The acceleration is due to fading adjustment costs from the Affordable Care Act, which had weighed on hospital profitability and employment in particular. In addition, declining uninsured rates due to the Affordable Care Act and state Medicaid expansions are increasing the demand for healthcare services as well.

The tightening in the job market and increased churn have boosted income as jobs are more plentiful and employers must increasingly raise wages to hire and retain workers. Real income growth to the second quarter, the most recent available data, has outpaced the forecast by almost a full percentage point. The added income has boosted consumer spending, which has benefited leisure/hospitality. Employment in leisure/hospitality is rising nearly twice as fast as overall employment, and is now well above last year's forecast.

Manufacturing employment is up slightly from a year ago as it outperformed in 2014 before falling short of expectations this year. Manufacturing is an important driver, particularly in many of the territory's Midwest metal-producing and auto-related metro areas. A stronger dollar has held job growth back recently by eroding international competitiveness of manufacturing exports. However, manufacturing has benefited from robust growth in auto demand and transportation equipment manufacturing, which significantly outpaced overall factory production over the last year. Toledo OH, for example, experienced fast growth because of its auto assemblers and parts manufacturers. U.S. vehicle sales are robust, exceeding 18 million annualized units in each of the past three months.

Finance has been another source of job gains, outperforming the forecast for most of the last year. One factor is that headwinds from a recent spate of bank mergers and acquisitions have eased. In recent years, mergers and acquisitions have weighed on growth as banks have sought efficiencies and economies of scale. BB&T Corp. alone has spent $4.3 billion on acquisitions in Pennsylvania, making it the fourth largest bank in the state. These headwinds appear to have weakened somewhat in 2015, however finance in the service territory is still lagging that of

[1] The metro definitions used were changed by the U.S. Office of Management and Budget, making a comparison of the 2014 to 2015 forecast impossible for the full service territory. When direct comparisons of the 2014 and 2015 forecast for the service territory are discussed, they will refer to only a subset of the metro areas and metro divisions for which this comparison is possible. These areas cover 71% of the total service territory employment.

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the U.S. overall, which suggests they remain a factor. Also, financial market conditions tightened in the second half of this year amid initial concerns about the Fed's exit strategy and the deterioration in China's economy.

While some metro areas grew fast in the service territory, others suffered job losses this year. The biggest losses were in Atlantic City NJ, where the casino industry has struggled under stiff regional competition. Total employment in the Atlantic City metro area is among the lowest since the early 1990s. Lebanon PA was also one of the worst-performing metro areas, in part because of the closing of a large distribution center.

While the economy is improving overall, the service territory is adding jobs more slowly than the nation partly because low growth in government employment has disproportionately affected the service territory. Federal government accounts for 3% of total employment, compared with 2% in the rest of the U.S. The concentration is noticeably higher in the District of Columbia, Maryland, and Virginia. Moreover, federal workers earn more in the Mid-Atlantic than elsewhere in the country. Therefore, federal layoffs do more damage to incomes.

Local government is adding jobs again thanks to steady improvement in the housing market that has lifted property taxes. However, it remains a source of weakness in some areas because of state and local fiscal problems, in particular Illinois and Pennsylvania. Increasing pension costs are weighing on some areas, which has led local government employment to fall in Philadelphia, Allentown-Bethlehem and Lebanon PA.

Pennsylvania and Ohio are steadily adding jobs, which account for a substantial portion of PJM's customers. Ohio and Pennsylvania metro areas make up 36% of the territory's payroll employment.

Ohio's recovery remains on track, driven by robust gains in high-paying professional and financial services as well as healthcare. High-value-added white-collar services including consulting and computer systems design are booming in Cincinnati and Columbus. Auto manufacturing is also powering forward thanks to major capital investments and rising national vehicle demand even though broad-based growth in the factory sector has eased because of protracted weakness in steel production.

Pennsylvania's economy is improving, but poor demographics and state fiscal problems are limiting job growth, which ranks in the bottom quintile of U.S. states.

Income growth across the region is helping tourism flourish and generating strong job gains in arts/entertainment/recreation, especially in Philadelphia, Pittsburgh and Allentown-Bethlehem.

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Near-term outlook and changes to the forecast

The October 2015 regional baseline forecast was generated in the context of the U.S. macro forecast. Changes to the near-term outlook for the PJM service territory are similar to those in the U.S. macro forecast. The recent performance was slightly weaker than expected. As a result, the forecast has been lowered for the next few quarters, but raised starting in the end of 2016.

Manufacturing is an area that fell short of expectations in 2015 because of the stronger dollar, low energy prices, weakness in global demand, and a turn in the inventory cycle in the second half of the year. However, following a wider U.S. trend, the near-term outlook for manufacturing job growth has been lifted, and employment is expected to expand through the end of 2017. Manufacturing employment grew an estimated 1.3% since the third quarter of 2014, falling short of expectations of a 1.7% increase. As the U.S. economy heats up over the next two years, this will spur more domestic demand for manufacturing and drive job growth.

The single-family housing market has improved somewhat, but the robust catch-up in single-family permitting that was expected has not materialized. Long-lasting scars from the Great Recession and slack in the job market have left households hesitant to make the investment in single-family housing. This has spurred demand for multifamily housing, but not enough to prevent overall permitting from falling short of the forecast.

Despite the disappointing housing market, construction employment in the service territory has tracked the forecast as commercial and infrastructure projects have helped fill the gap. Both Pennsylvania and Illinois have passed significant infrastructure spending bills in recent years. In Pennsylvania, more than $1.7 billion is being spent on turnpike projects alone in 2015.

Overall, the return of the service territory economy to full employment will be more gradual than expected, and as a result above-trend job growth will last longer than previously expected. This short-term outlook mirrors the U.S. macro forecast. Over the past year, the service sector has fallen short of expectations. Service growth will improve into 2016 and deliver a less rapid but more prolonged recovery period before settling into longer-term growth rates.

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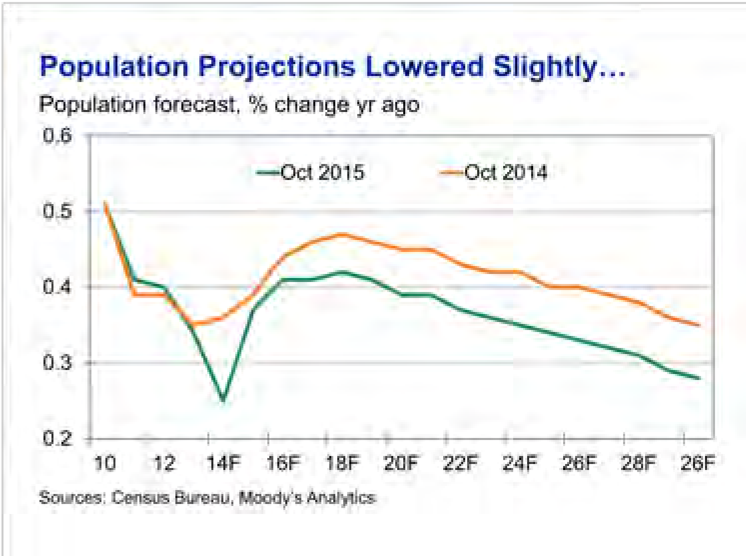
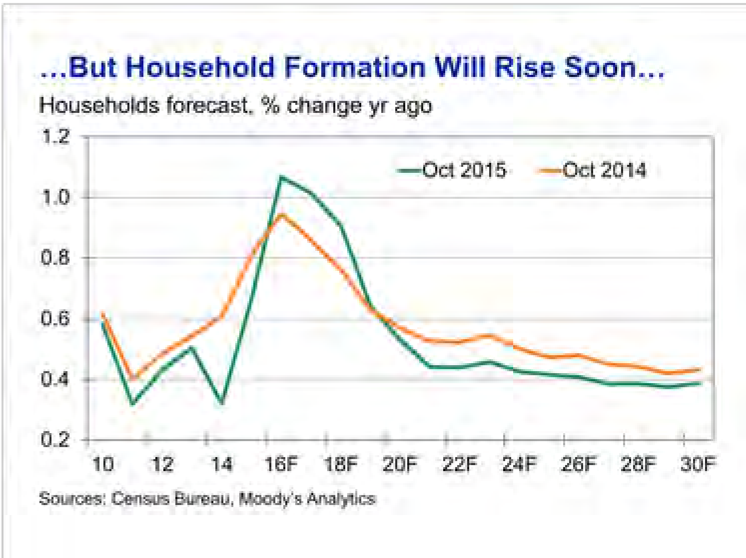
Long-term outlook

The October 2015 forecast for long-term GDP growth in metro areas in the PJM service territory has been slightly upgraded from 2014. Over the next few years, faster household formation than previously expected will boost economic growth.



For the metro areas in the service territory that are comparable to the previous forecast, the October 2015 forecast is for population to expand 5.7% between 2015 and 2030, down from 6.6% in the October 2014 forecast. As a result the forecast population will be 435,000 lower by 2030 than previously expected. For the full service territory, including newly added and changed metro areas, population growth over this period will be 7%.



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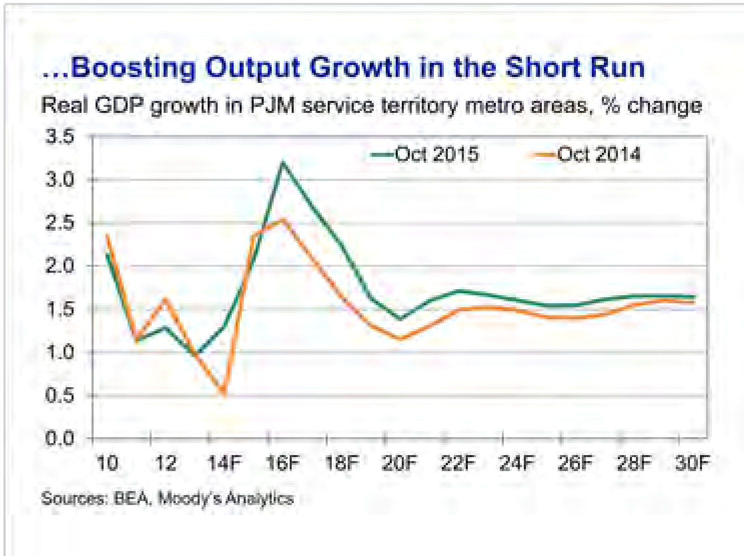
Weaker population growth translates to fewer households in the long run. However, in the near term the household formation rate is expected to increase thanks to an improving economy. Scars from the Great Recession have kept the household formation rate below equilibrium. As the labor market tightens and income growth accelerates over the next two years, household formation will pick up and make up for lost ground. Once catch-up household formation has been exhausted, the formation rate will decline to levels consistent with the service territory's slowly growing population.



Overall, the long-term GDP forecast has not been altered substantially. The PJM service territory will underperform the U.S., with average annual real GDP growth of 1.9% from 2016 to 2030, compared with the U.S. average of 2.1%. Relative to last year, GDP growth in the parts of the service territory that are comparable to last year are expected to grow 0.2 percentage point faster.

The southernmost metro areas, including the southern parts of Pennsylvania, are expected to be among the fastest-growing in the PJM service territory. The biggest comparative advantage for these areas is their favorable demographic trends, which will help boost overall final demand. While the long-term forecast is weaker, household formation will rebound in 2016 and will drive growth in consumer-based services, including education/healthcare and leisure/hospitality.

Suburban areas are outperforming the cities they neighbor in several cases, thanks to higher levels of education and the regulatory and policy problems that big cities face. For example, the Elgin metro division is expected to outpace the Chicago metro division in terms of population and GDP growth, and Montgomery-Bucks-Chester will do the same for Philadelphia. Washington DC will outperform the service territory thanks to a highly educated labor force, productivity growth, and positive demographic trends.

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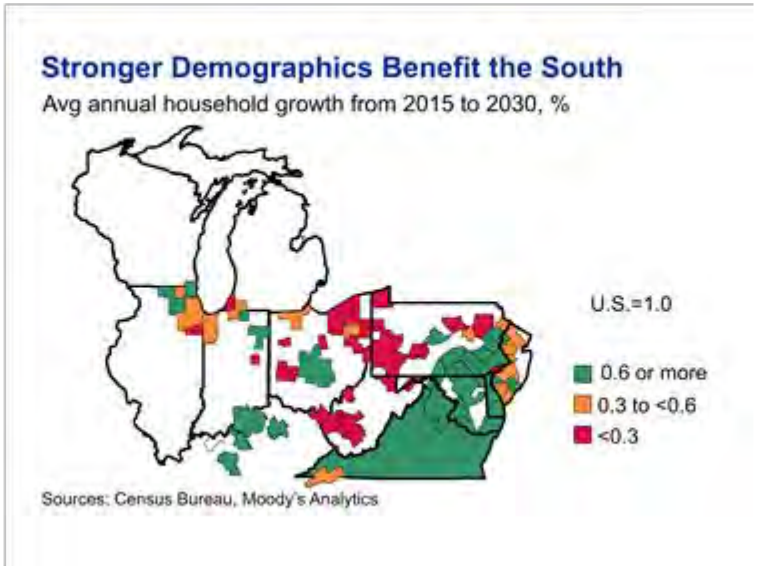
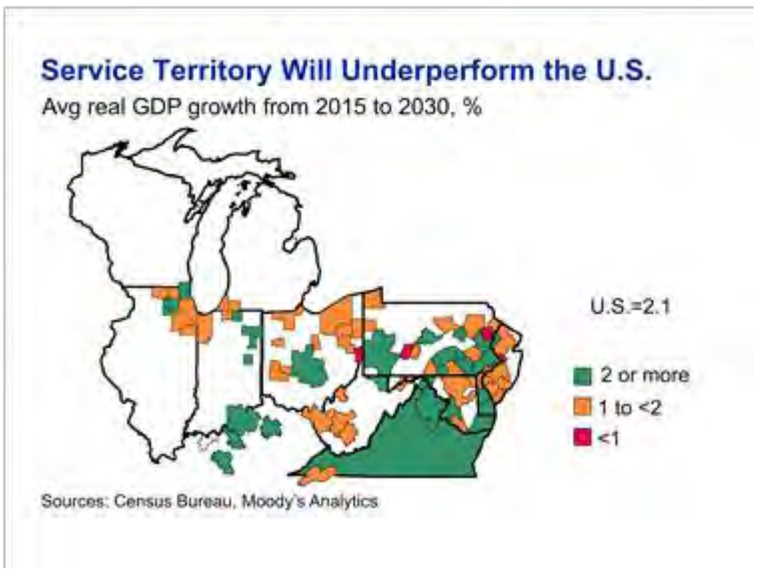
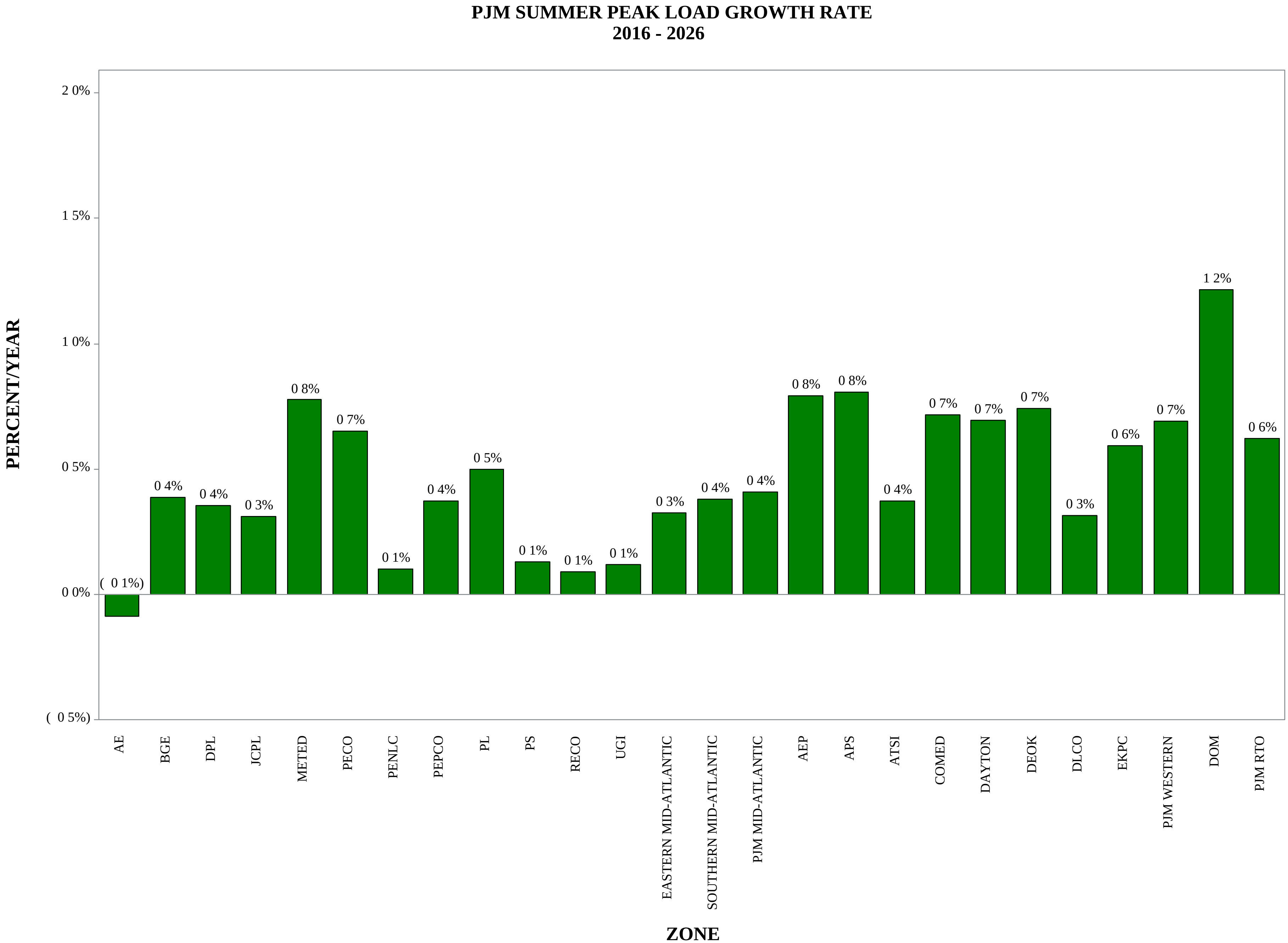
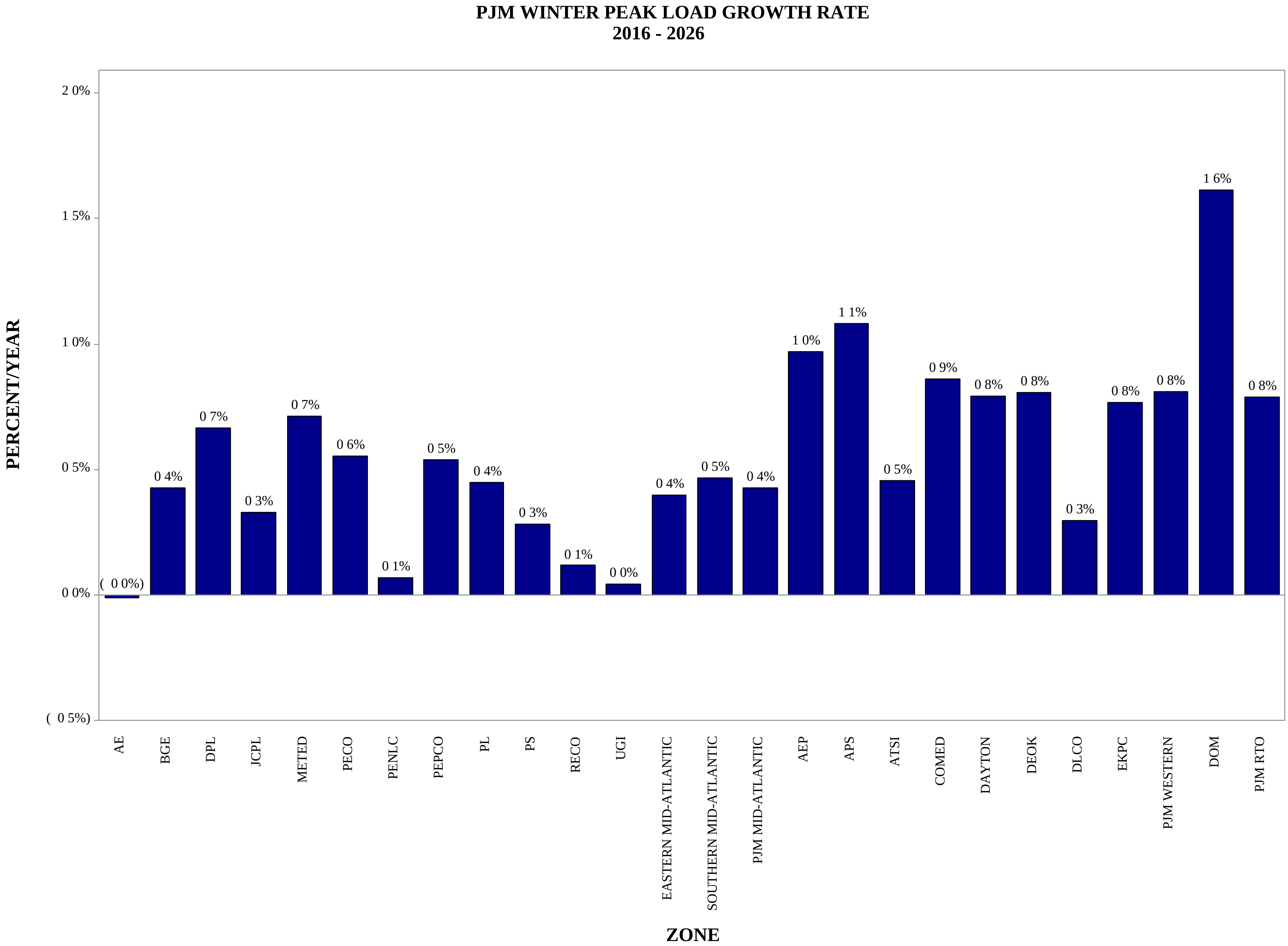


Metro areas in Ohio, West Virginia, and western and northern Pennsylvania will expand more slowly. Expansion in those states will be more restrained as the region transitions away from manufacturing toward more service-oriented economies. With lower-value-added services accounting for a larger part of the regional economies, income gains are expected to be more restrained. Weaker demographics will also undermine long-term growth, as workers and their families are expected to seek opportunities in stronger labor markets outside of the slow-growth metro areas in the Midwest and Northeast.



Of the 10 areas with the weakest increases in the number of households, five are in Ohio and four are in Pennsylvania. Eight of these areas will post net declines in the number of households. In Pennsylvania, the long-run decline of manufacturing is exacerbated by poor public sector finances that will weigh on local government employment as well as taxpayers.


PJM SUMMER PEAK LOAD GROWTH RATE
2016 - 2026
PERCENT/YEAR
2 0%
1 5%
1 0%
0 5%
0 0%
(0 5%)
(0 1%)
0 4%
0 4%
0 3%
0 8%
0 7%
0 1%
0 4%
0 5%
0 1%
0 1%
0 1%
0 3%
0 4%
0 4%
0 8%
0 8%
0 4%
0 7%
0 7%
0 7%
0 3%
0 6%
0 7%
1 2%
0 6%
AE
BGE
DPL
JCPL
METED
PECO
PENLC
PEPCO
PL
PS
RECO
UGI
EASTERN MID-ATLANTIC
SOUTHERN MID-ATLANTIC
PJM MID-ATLANTIC
AEP
APS
ATSI
COMED
DAYTON
DEOK
DLCO
EKPC
PJM WESTERN
DOM
PJM RTO
ZONE


PJM WINTER PEAK LOAD GROWTH RATE
2016 - 2026
PERCENT/YEAR
2 0%
1 5%
1 0%
0 5%
0 0%
(0 5%)
(0 0%)
0 4%
0 7%
0 3%
0 7%
0 6%
0 1%
0 5%
0 4%
0 3%
0 1%
0 0%
0 4%
0 5%
0 4%
1 0%
1 1%
0 5%
0 9%
0 8%
0 8%
0 3%
0 8%
0 8%
1 6%
0 8%
AE
BGE
DPL
JCPL
METED
PECO
PENLC
PEPCO
PL
PS
RECO
UGI
EASTERN MID-ATLANTIC
SOUTHERN MID-ATLANTIC
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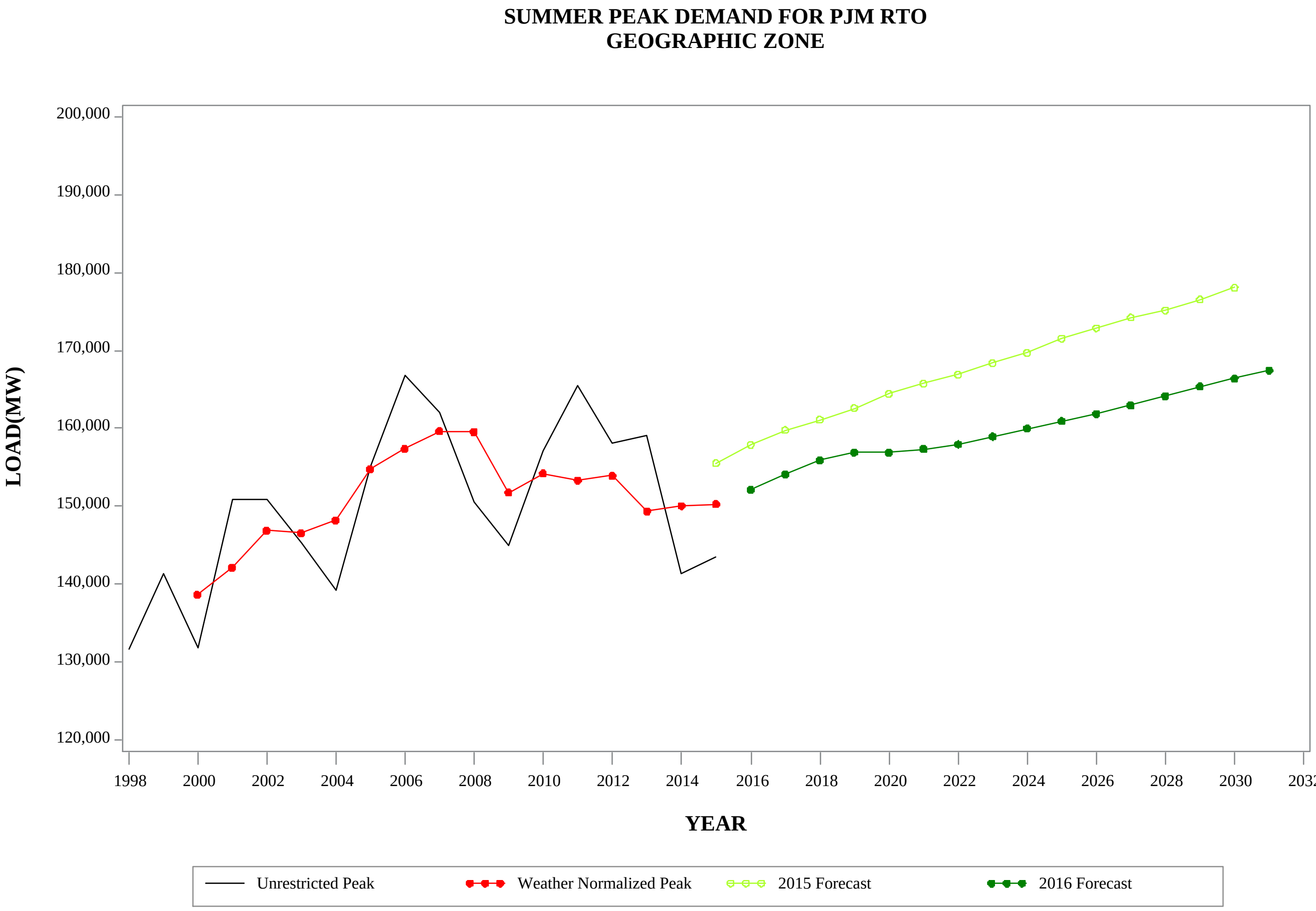
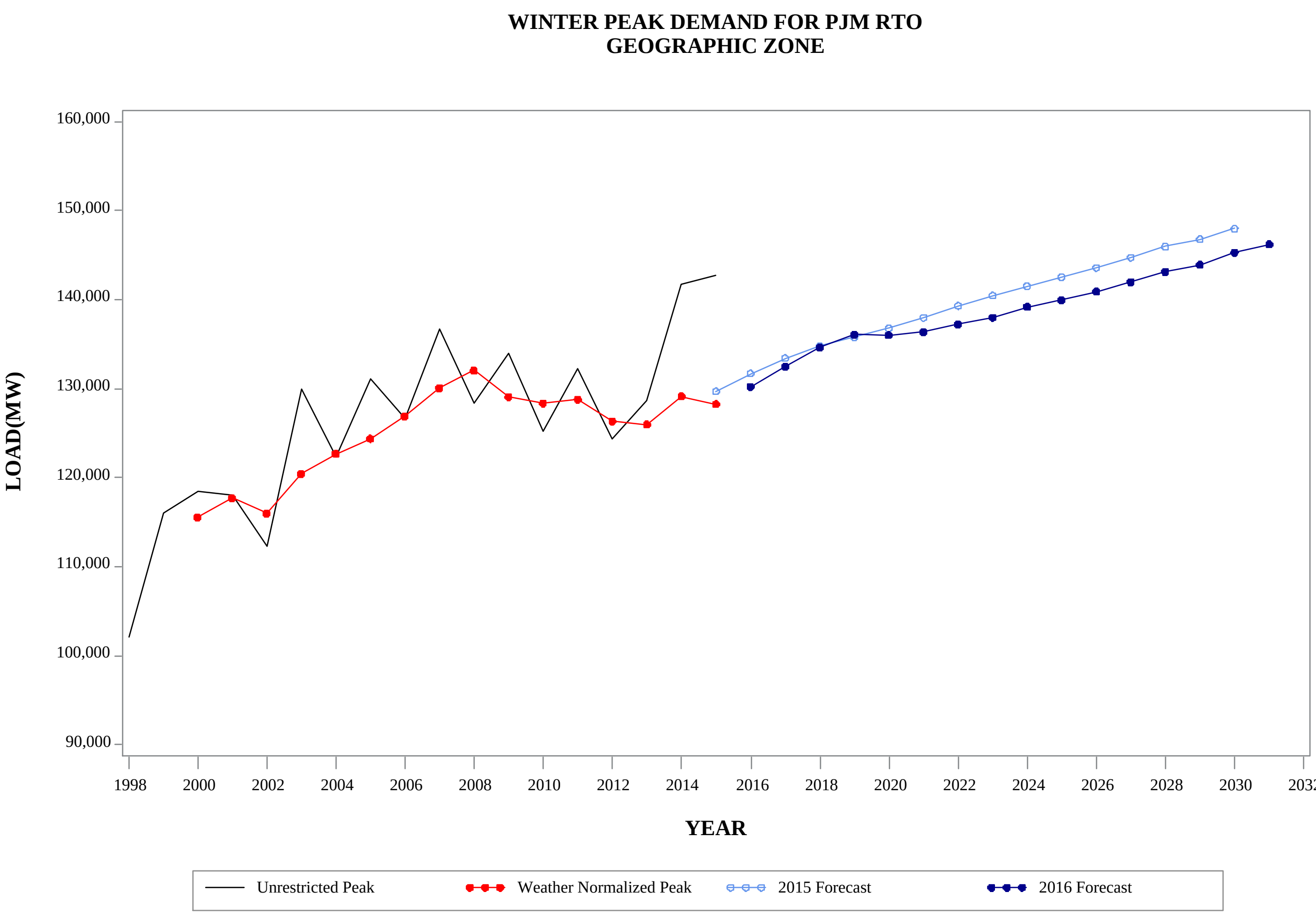
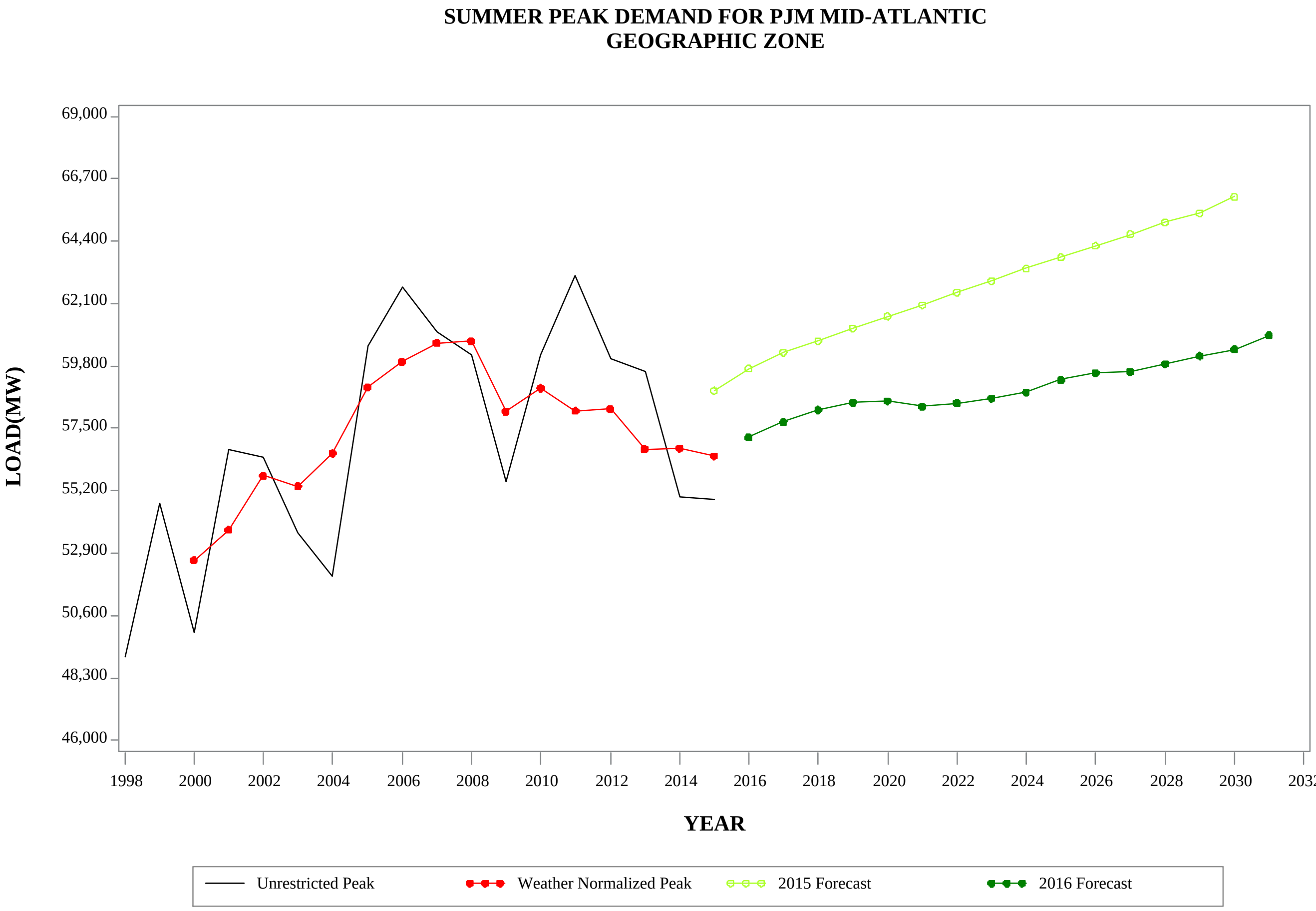
DLCO
EKPC
PJM WESTERN
DOM
PJM RTO
ZONE

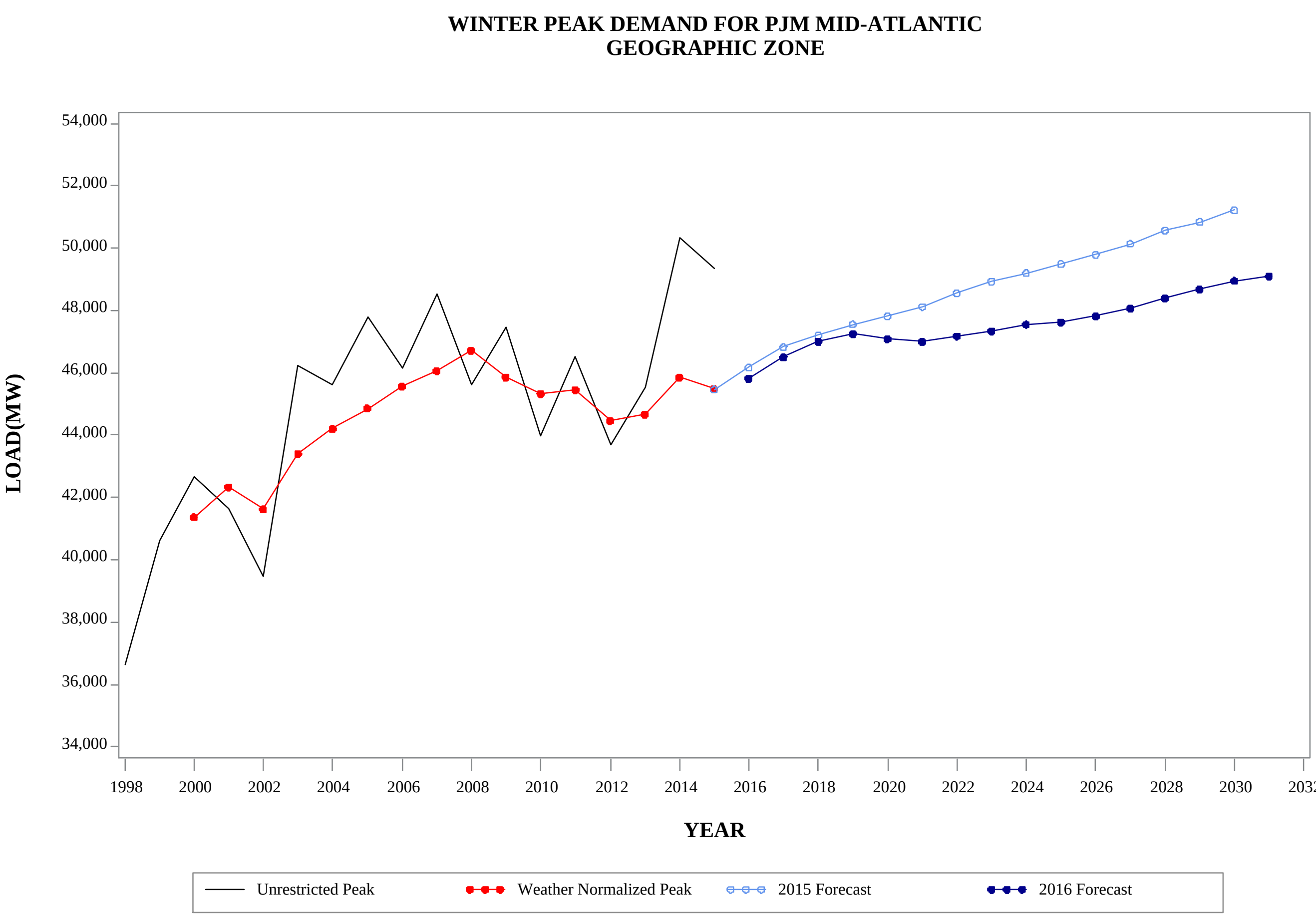


SUMMER PEAK DEMAND FOR PJM RTO
GEOGRAPHIC ZONE
200,000
190,000
180,000
170,000
160,000
150,000
140,000
130,000
120,000
LOAD(MW)
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
YEAR
Unrestricted Peak
Weather Normalized Peak
2015 Forecast
2016 Forecast

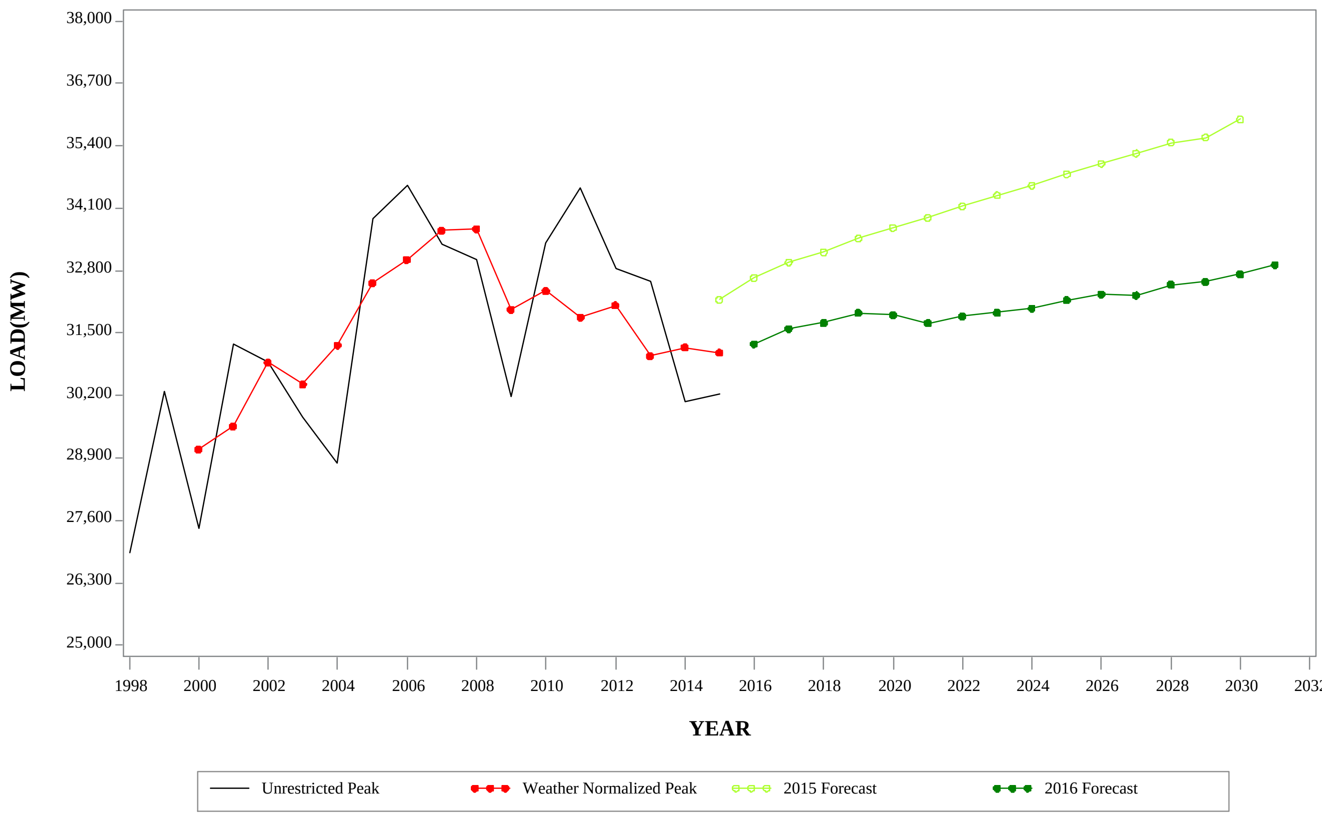


WINTER PEAK DEMAND FOR PJM RTO
GEOGRAPHIC ZONE
160,000
150,000
140,000
130,000
120,000
110,000
100,000
90,000
LOAD(MW)
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
YEAR
Unrestricted Peak
Weather Normalized Peak
2015 Forecast
2016 Forecast

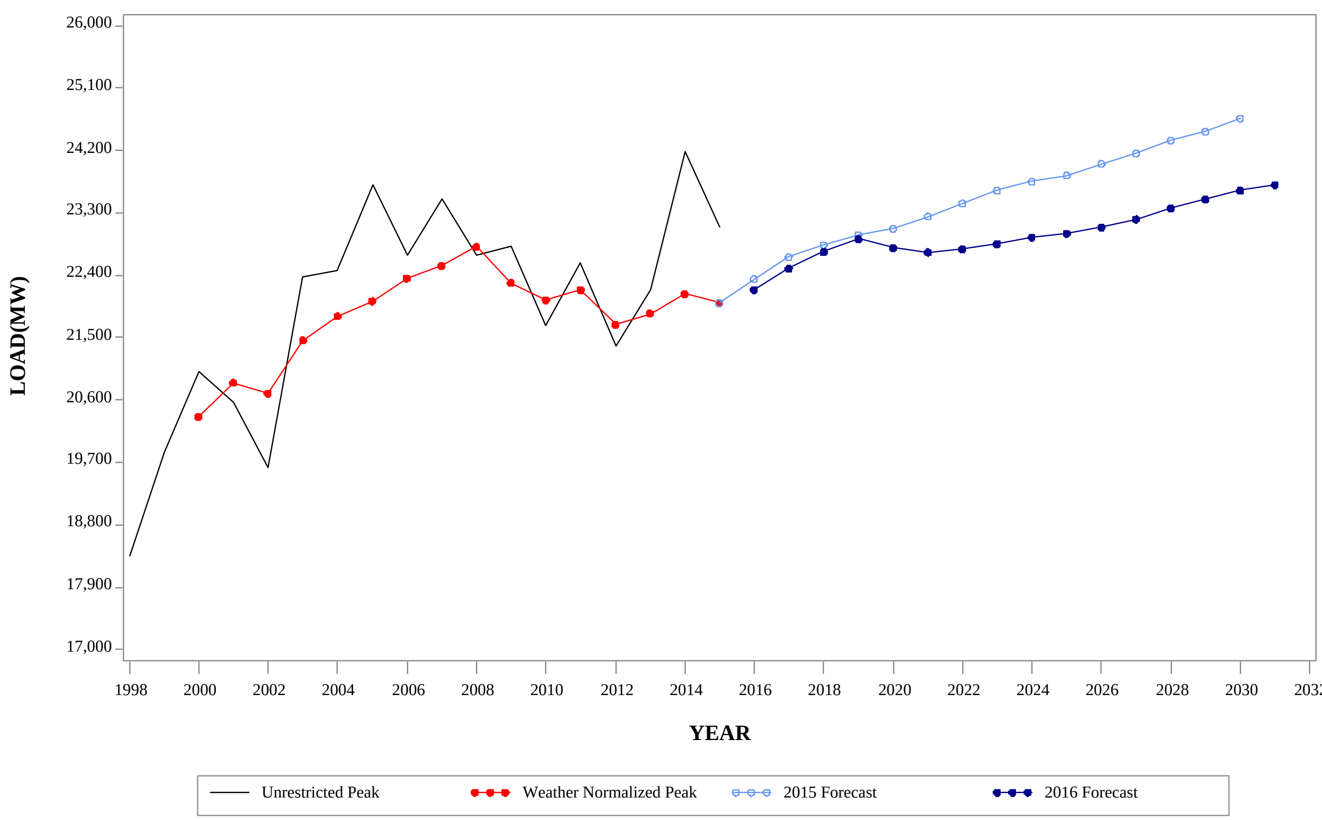

SUMMER PEAK DEMAND FOR PJM MID-ATLANTIC
GEOGRAPHIC ZONE
LOAD(MW)
69,000
66,700
64,400
62,100
59,800
57,500
55,200
52,900
50,600
48,300
46,000
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
YEAR
Unrestricted Peak
Weather Normalized Peak
2015 Forecast
2016 Forecast


WINTER PEAK DEMAND FOR PJM MID-ATLANTIC
GEOGRAPHIC ZONE
LOAD(MW)
54,000
52,000
50,000
48,000
46,000
44,000
42,000
40,000
38,000
36,000
34,000
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
YEAR
Unrestricted Peak
Weather Normalized Peak
2015 Forecast
2016 Forecast

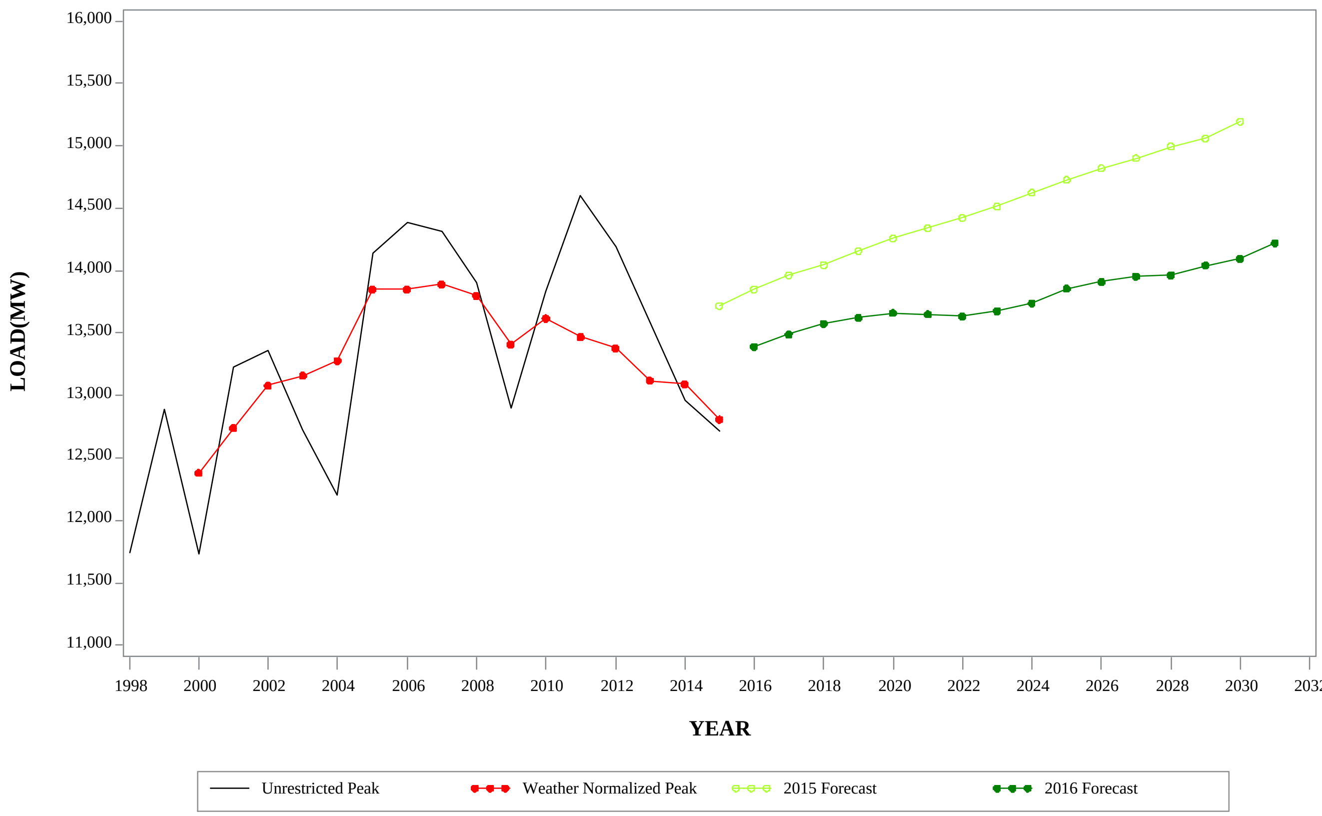
SUMMER PEAK DEMAND FOR EASTERN MID-ATLANTIC GEOGRAPHIC ZONE



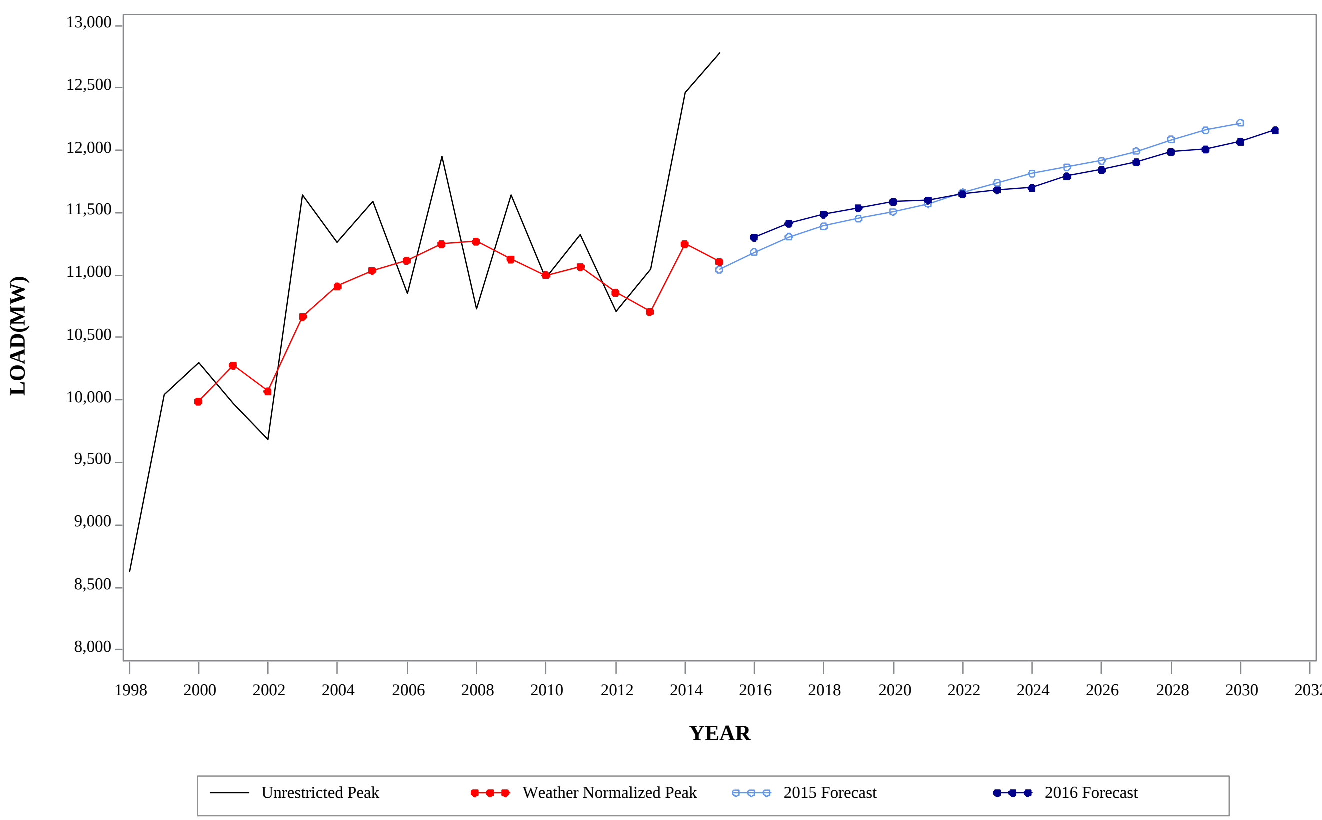
WINTER PEAK DEMAND FOR EASTERN MID-ATLANTIC GEOGRAPHIC ZONE



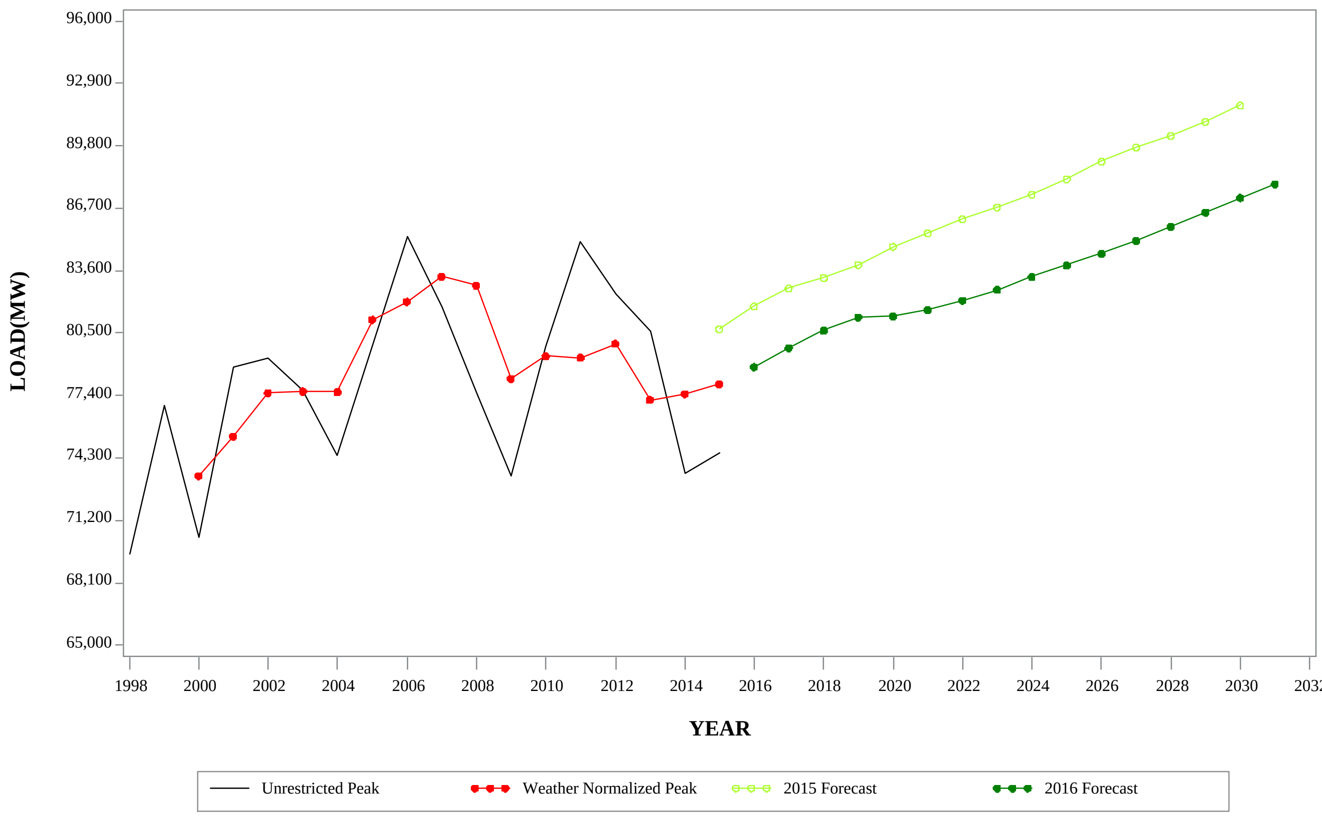
SUMMER PEAK DEMAND FOR SOUTHERN MID-ATLANTIC GEOGRAPHIC ZONE



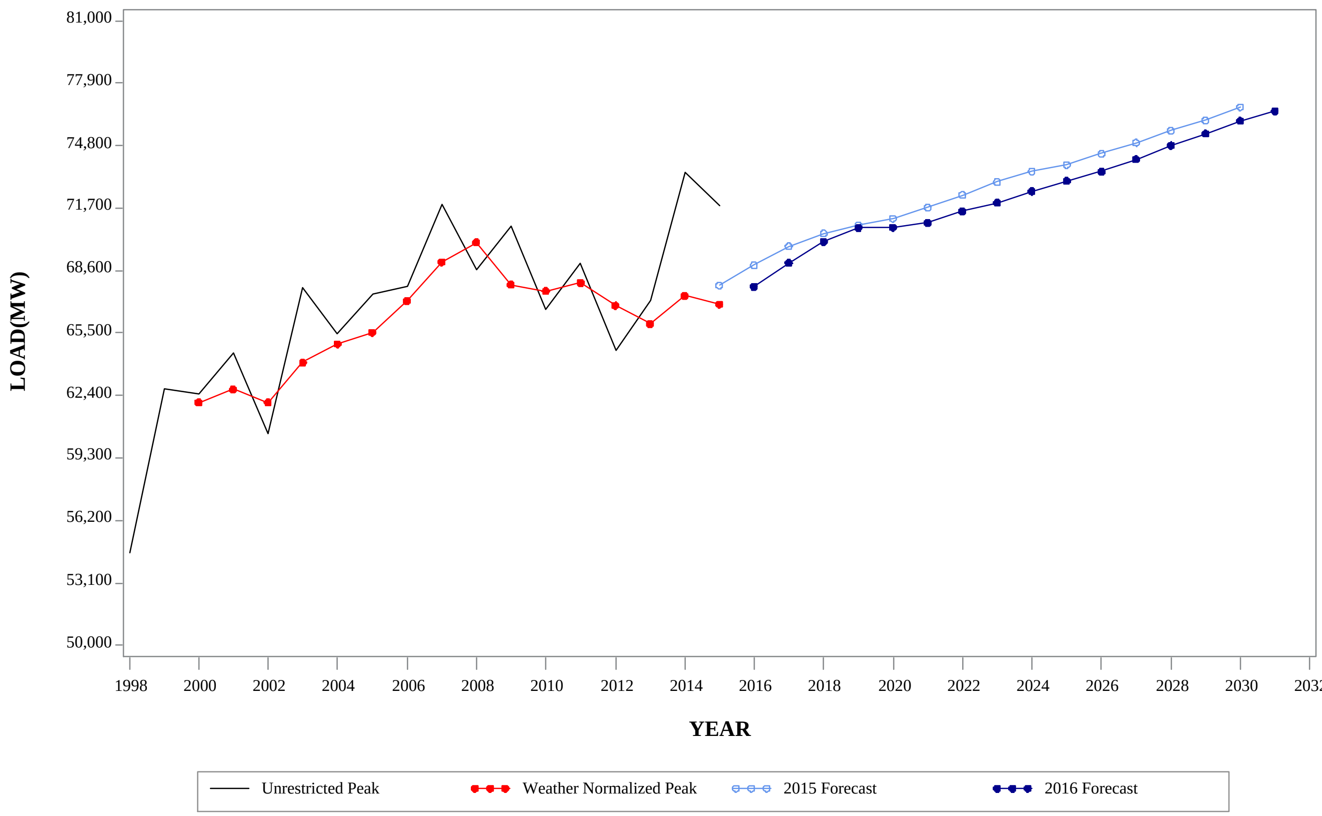
WINTER PEAK DEMAND FOR SOUTHERN MID-ATLANTIC GEOGRAPHIC ZONE



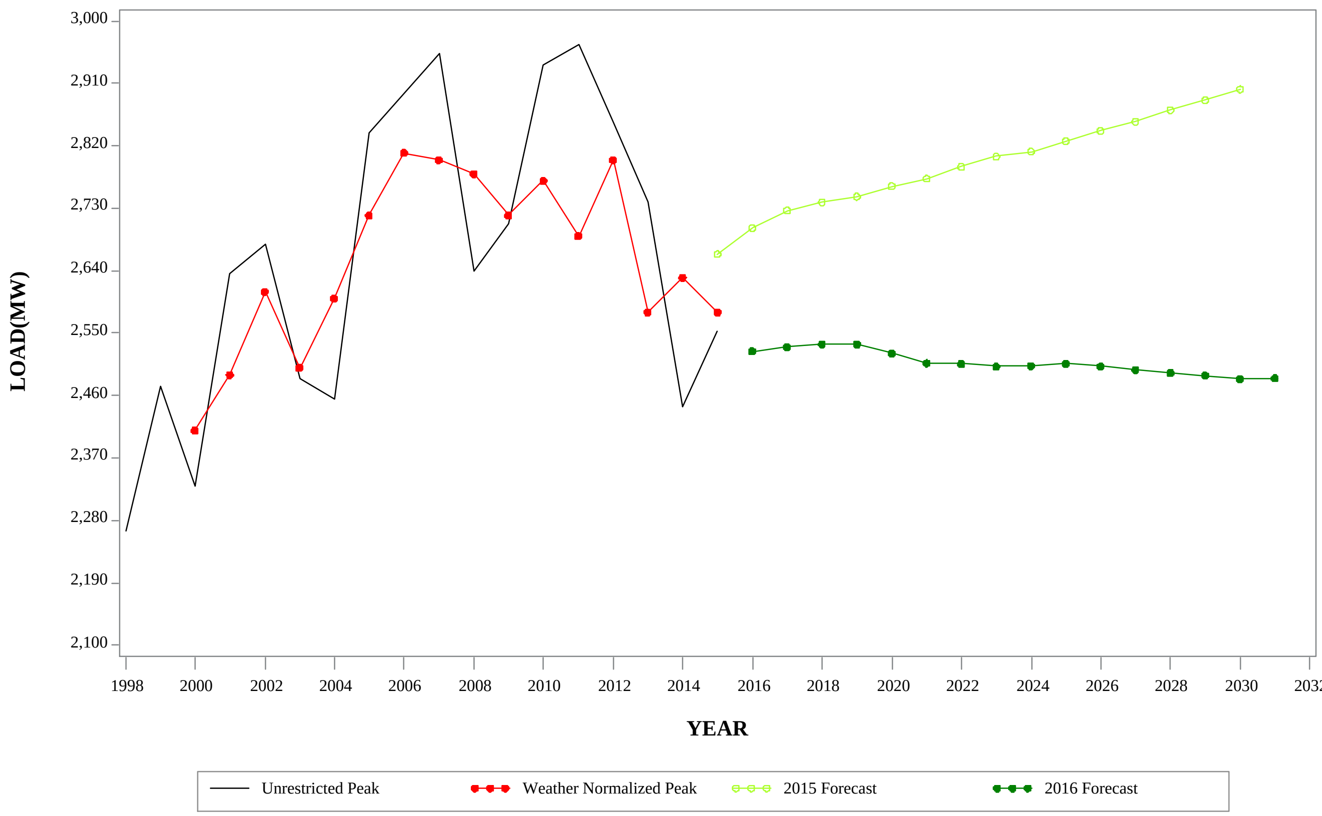
SUMMER PEAK DEMAND FOR PJM WESTERN GEOGRAPHIC ZONE



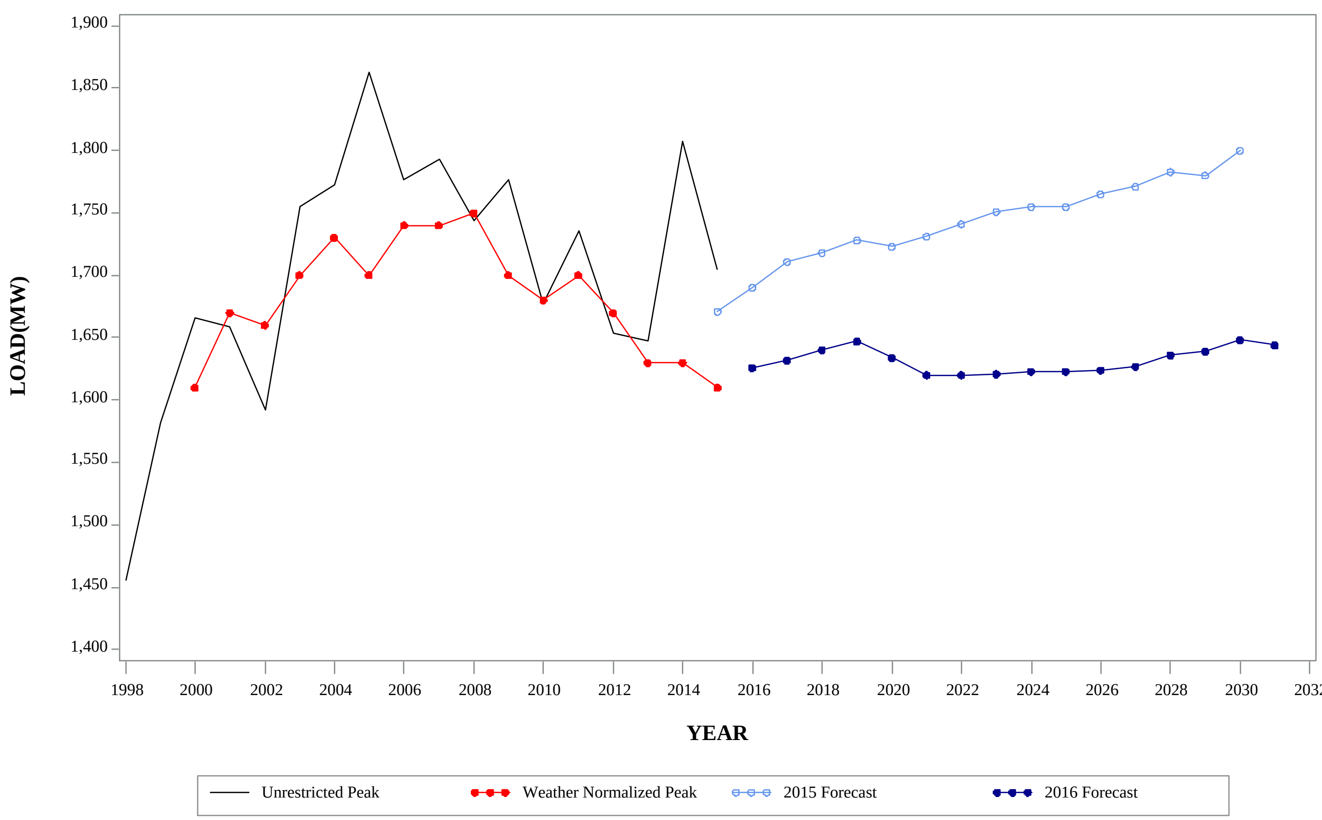
WINTER PEAK DEMAND FOR PJM WESTERN GEOGRAPHIC ZONE



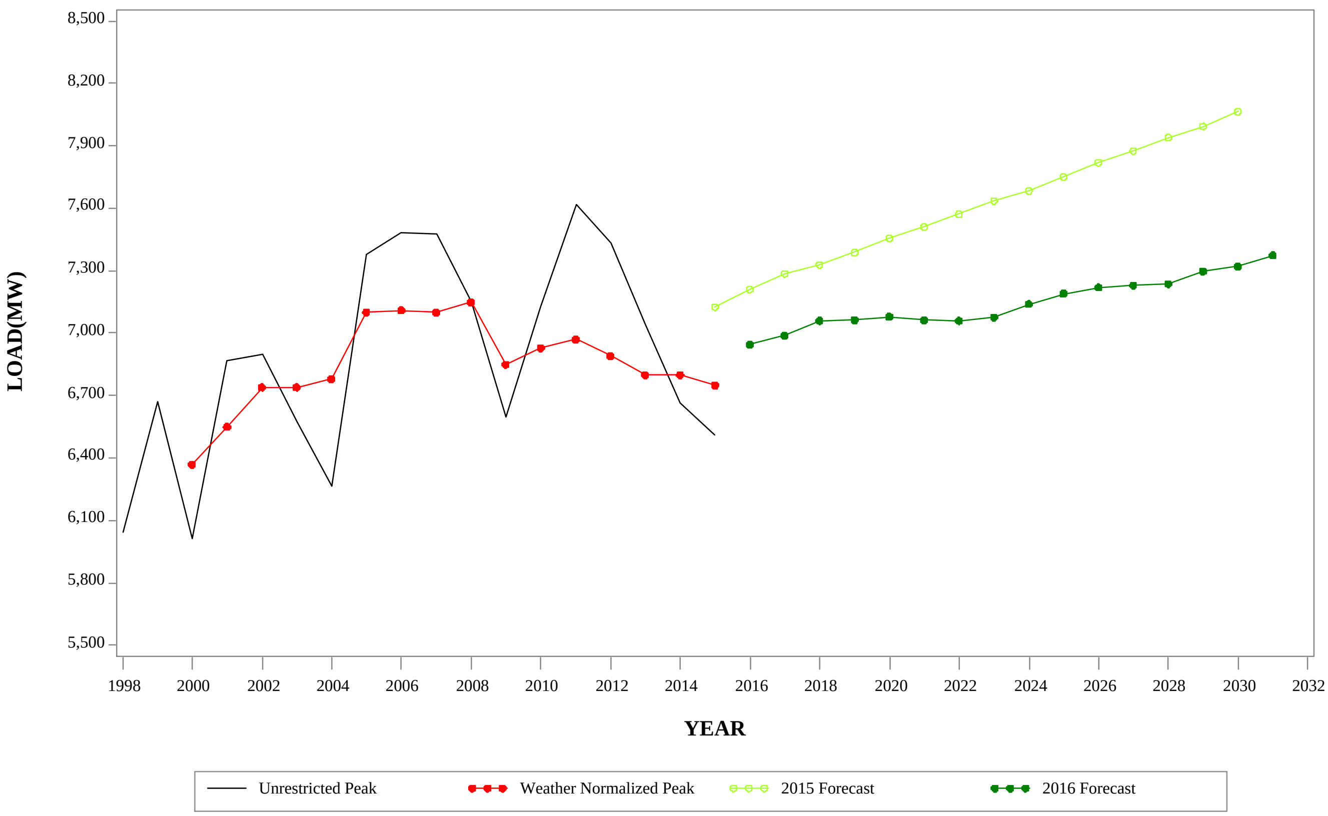
SUMMER PEAK DEMAND FOR AE GEOGRAPHIC ZONE



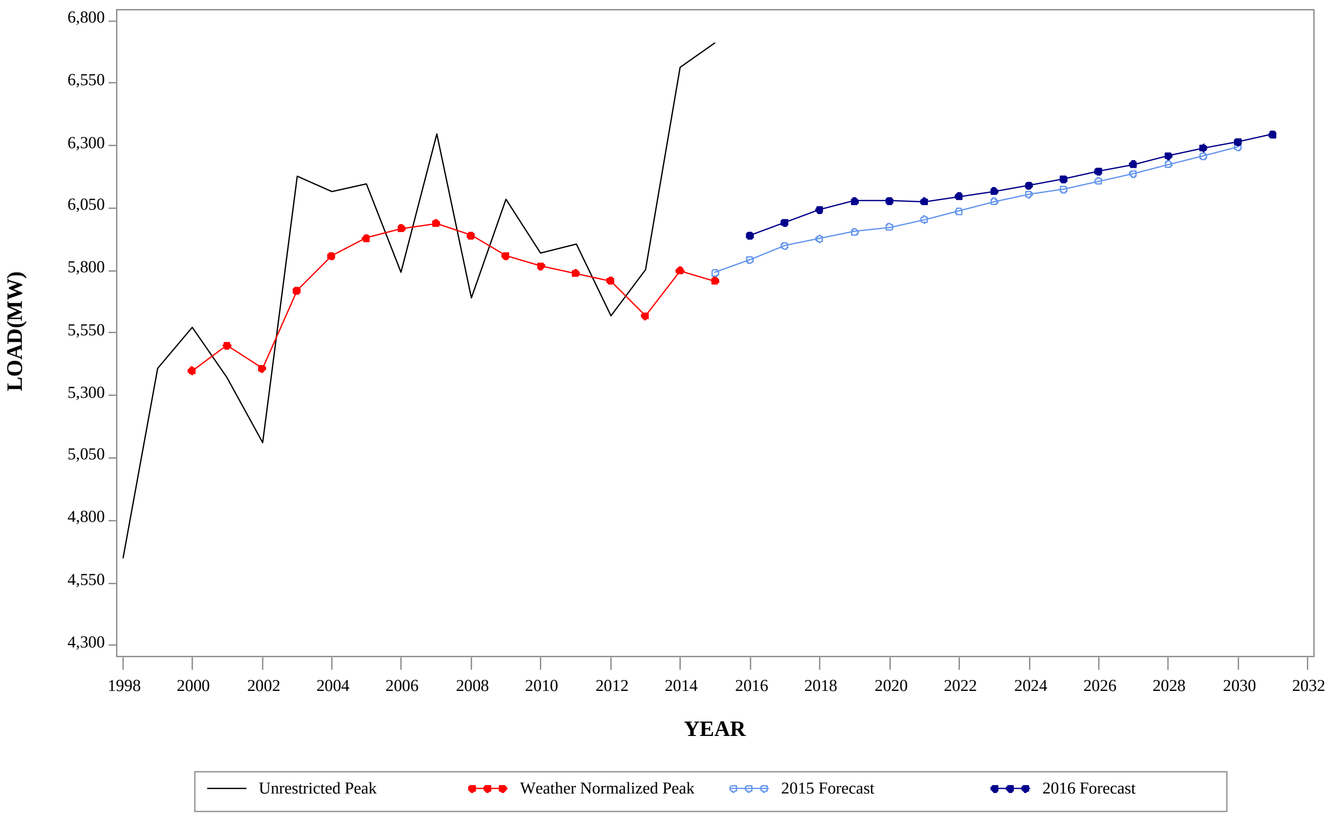
WINTER PEAK DEMAND FOR AE GEOGRAPHIC ZONE



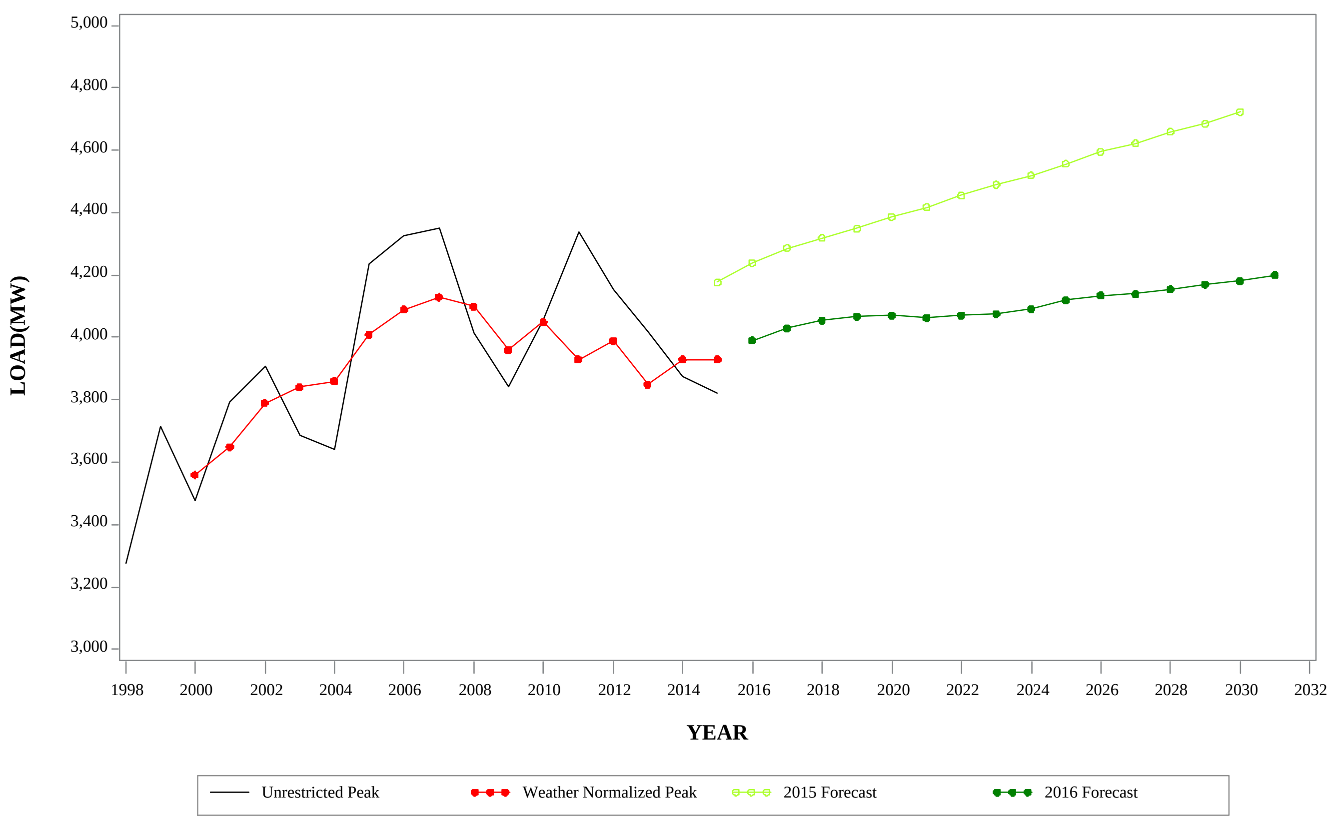
SUMMER PEAK DEMAND FOR BGE GEOGRAPHIC ZONE



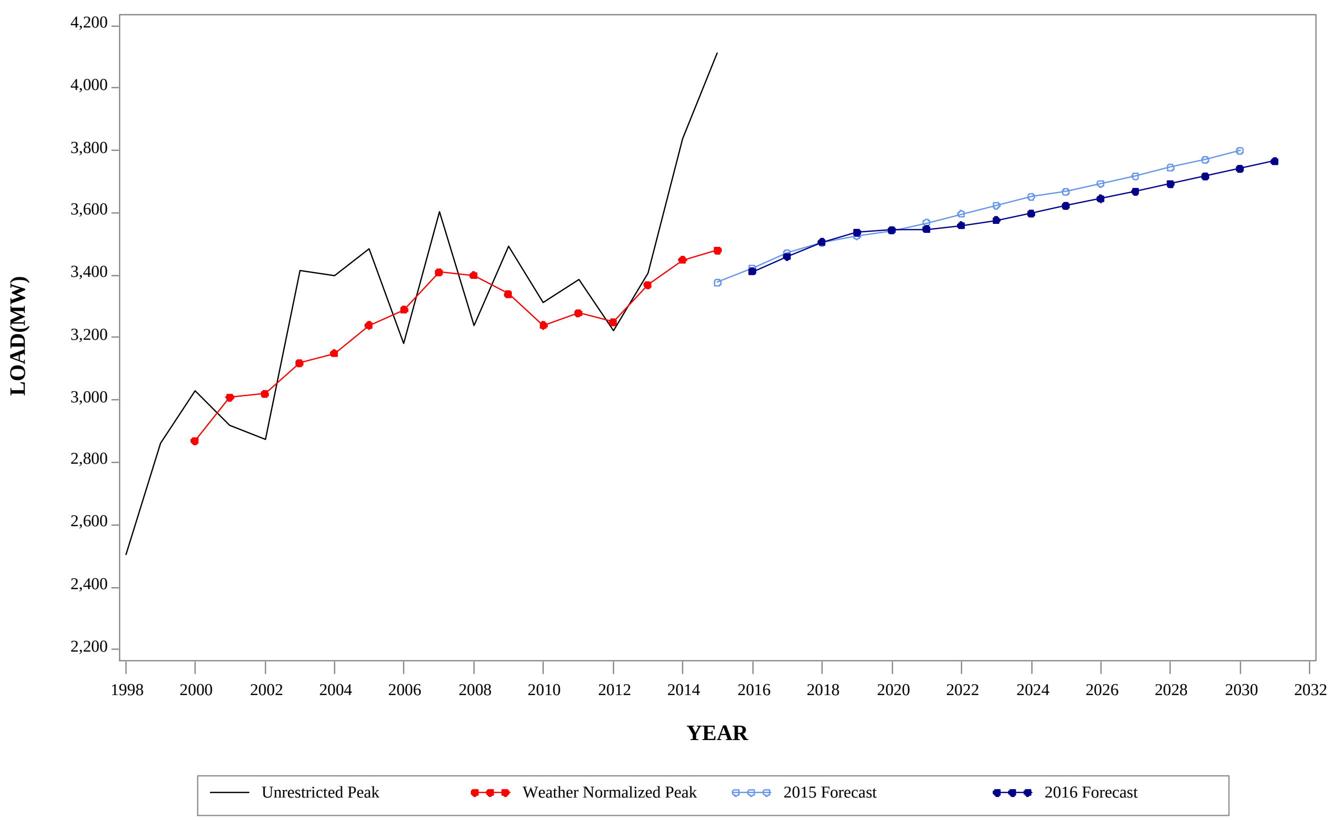
WINTER PEAK DEMAND FOR BGE GEOGRAPHIC ZONE



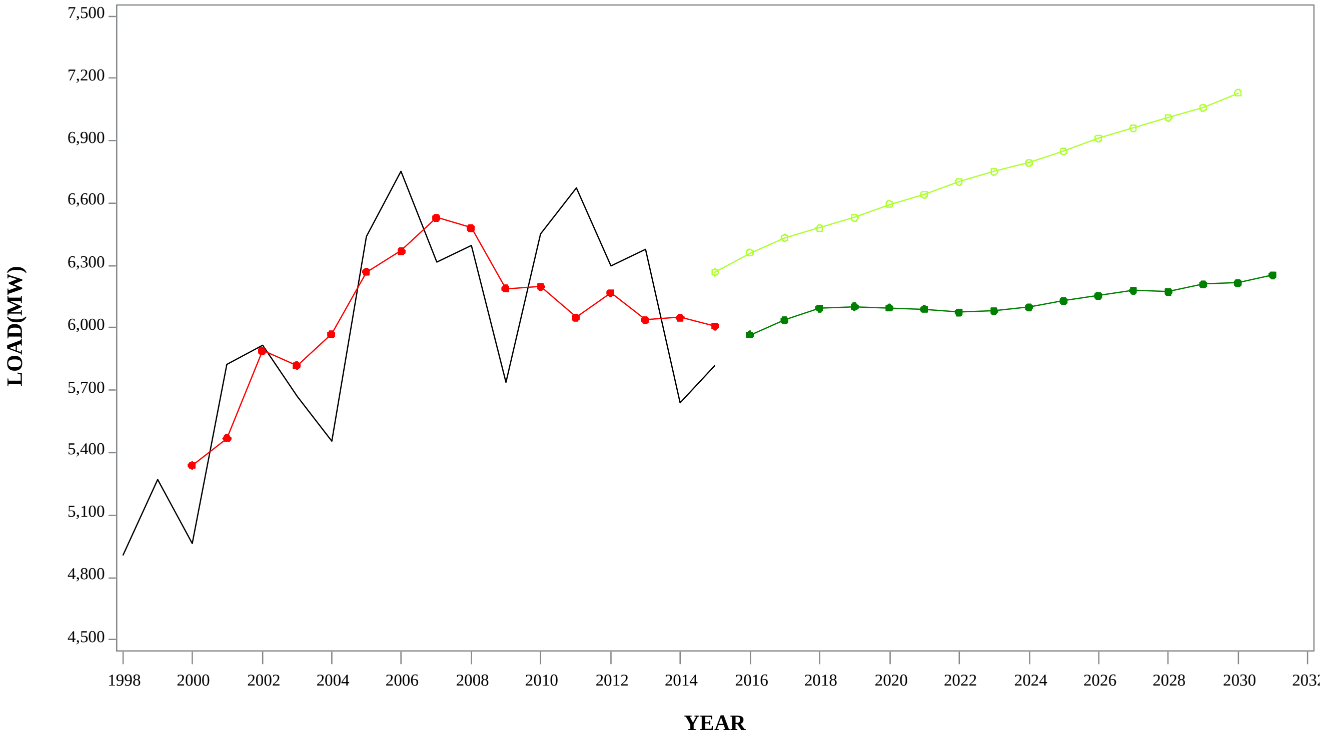
SUMMER PEAK DEMAND FOR DPL GEOGRAPHIC ZONE



WINTER PEAK DEMAND FOR DPL GEOGRAPHIC ZONE

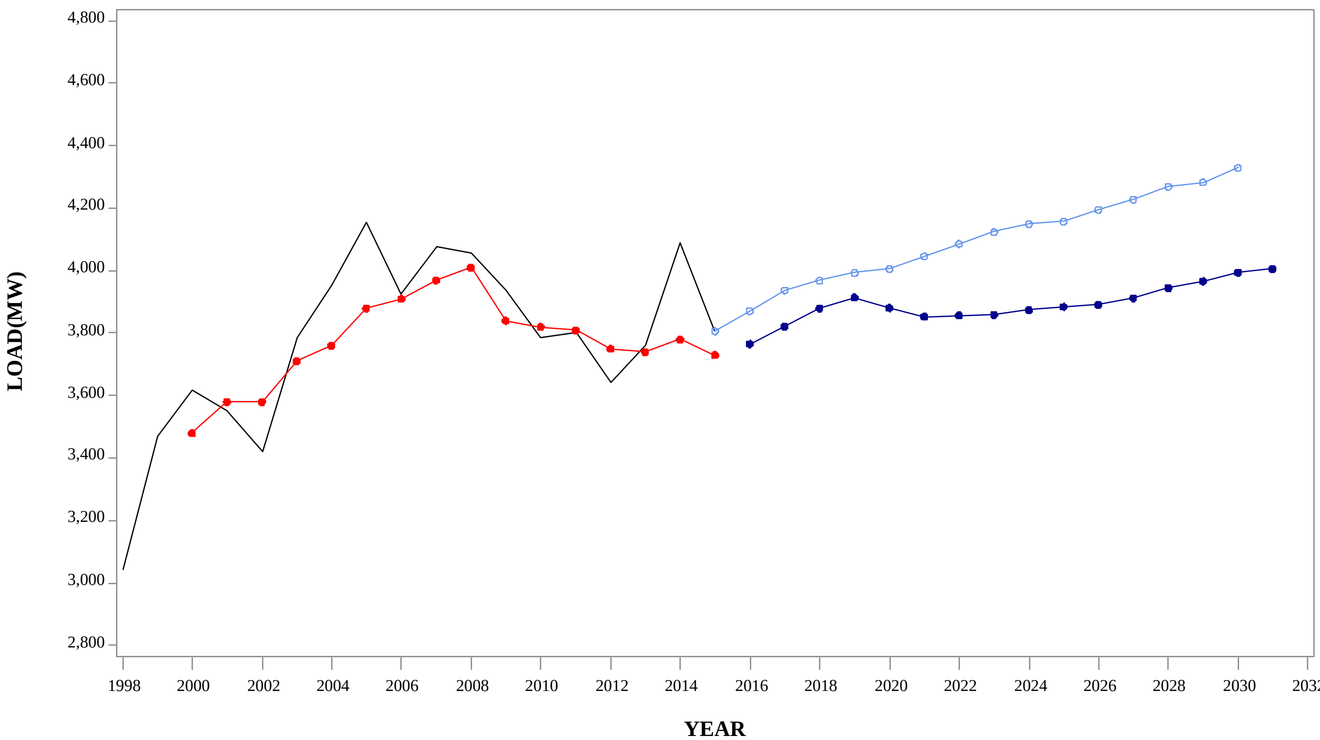


SUMMER PEAK DEMAND FOR JCPL GEOGRAPHIC ZONE



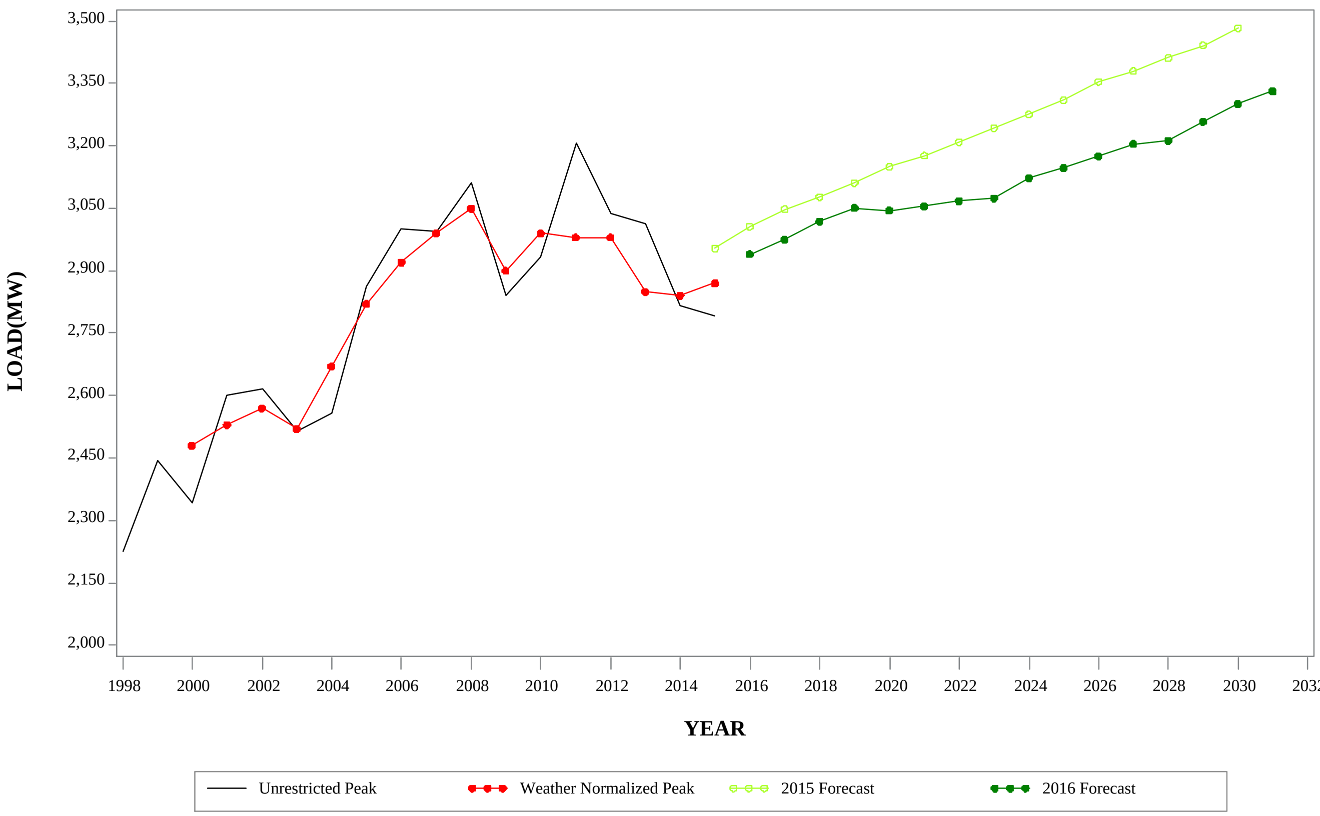
Unrestricted Peak | Weather Normalized Peak | 2015 Forecast | 2016 Forecast

WINTER PEAK DEMAND FOR JCPL GEOGRAPHIC ZONE

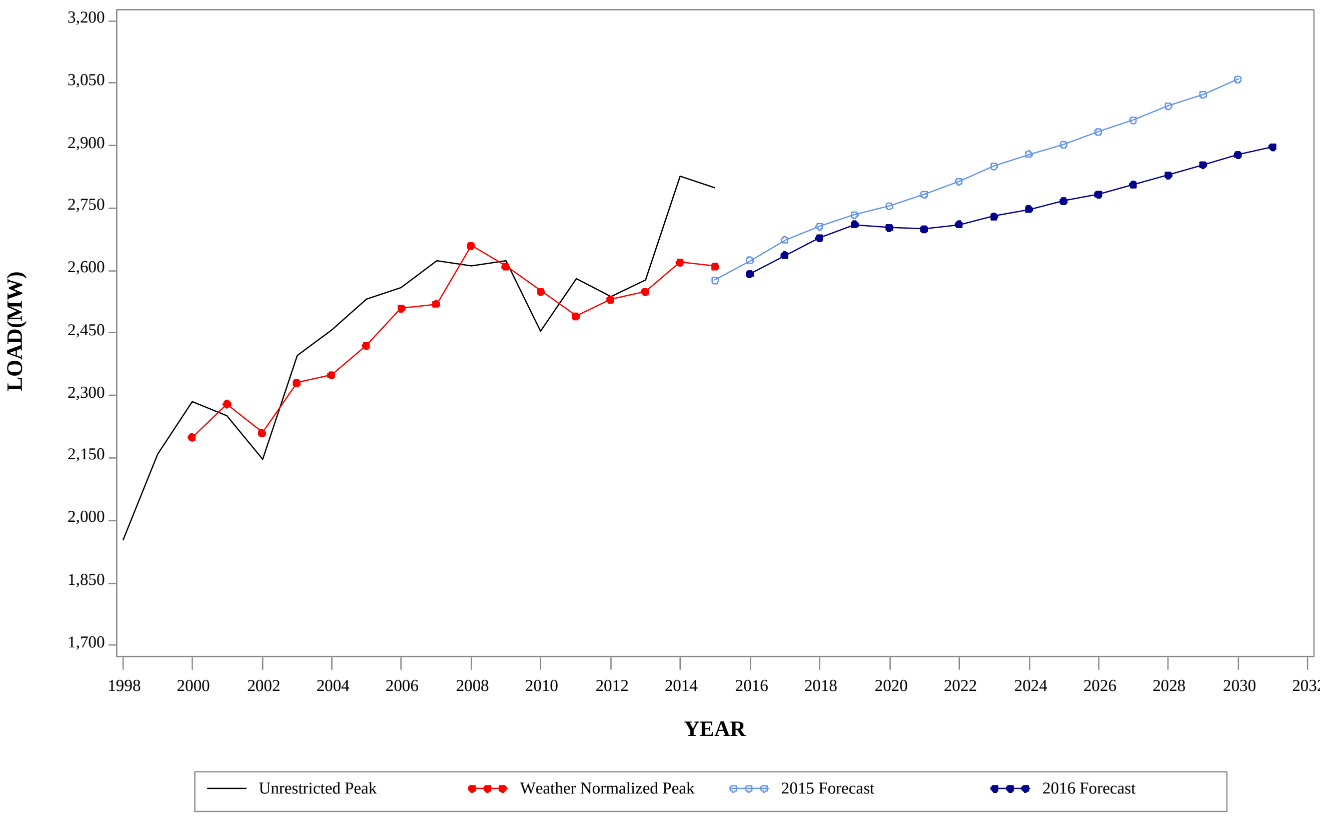


Unrestricted Peak | Weather Normalized Peak | 2015 Forecast | 2016 Forecast

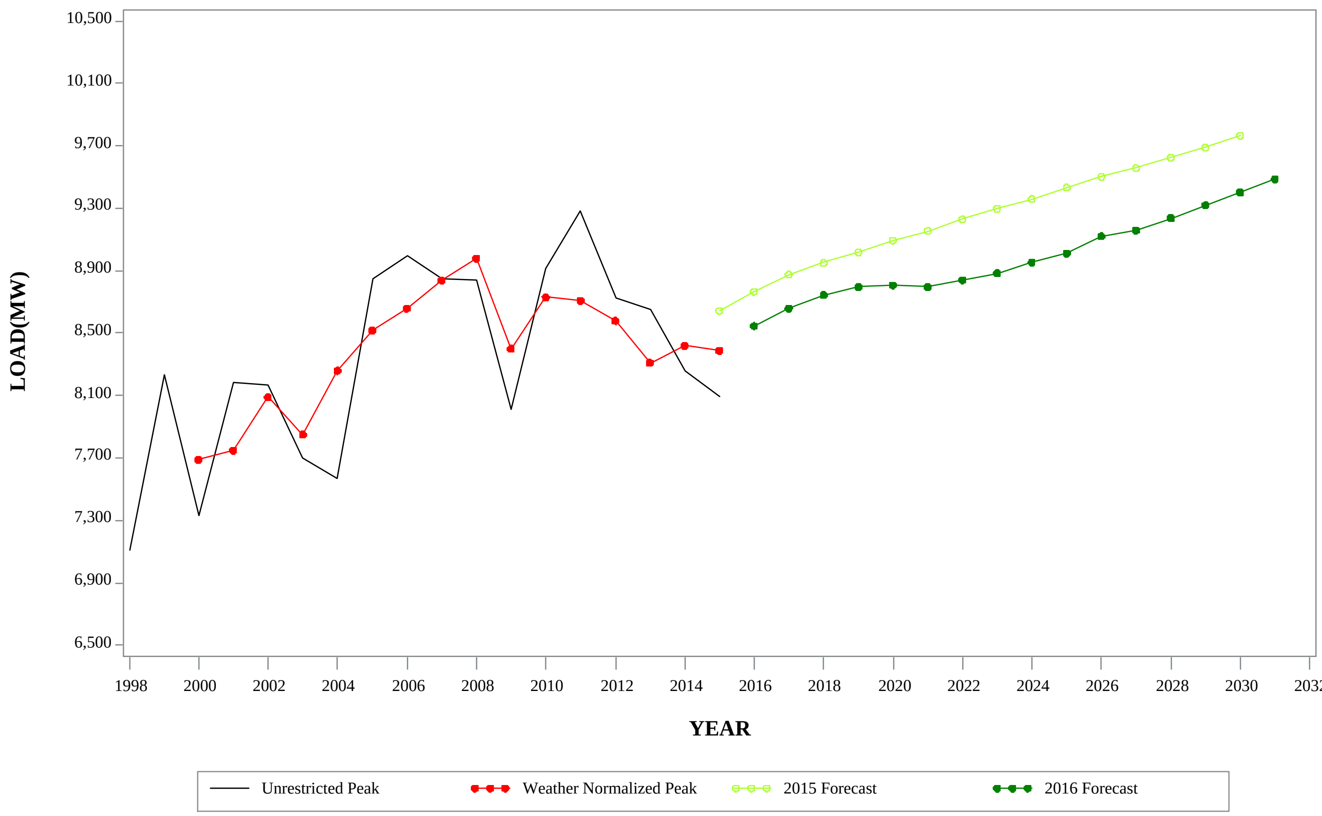
SUMMER PEAK DEMAND FOR METED GEOGRAPHIC ZONE



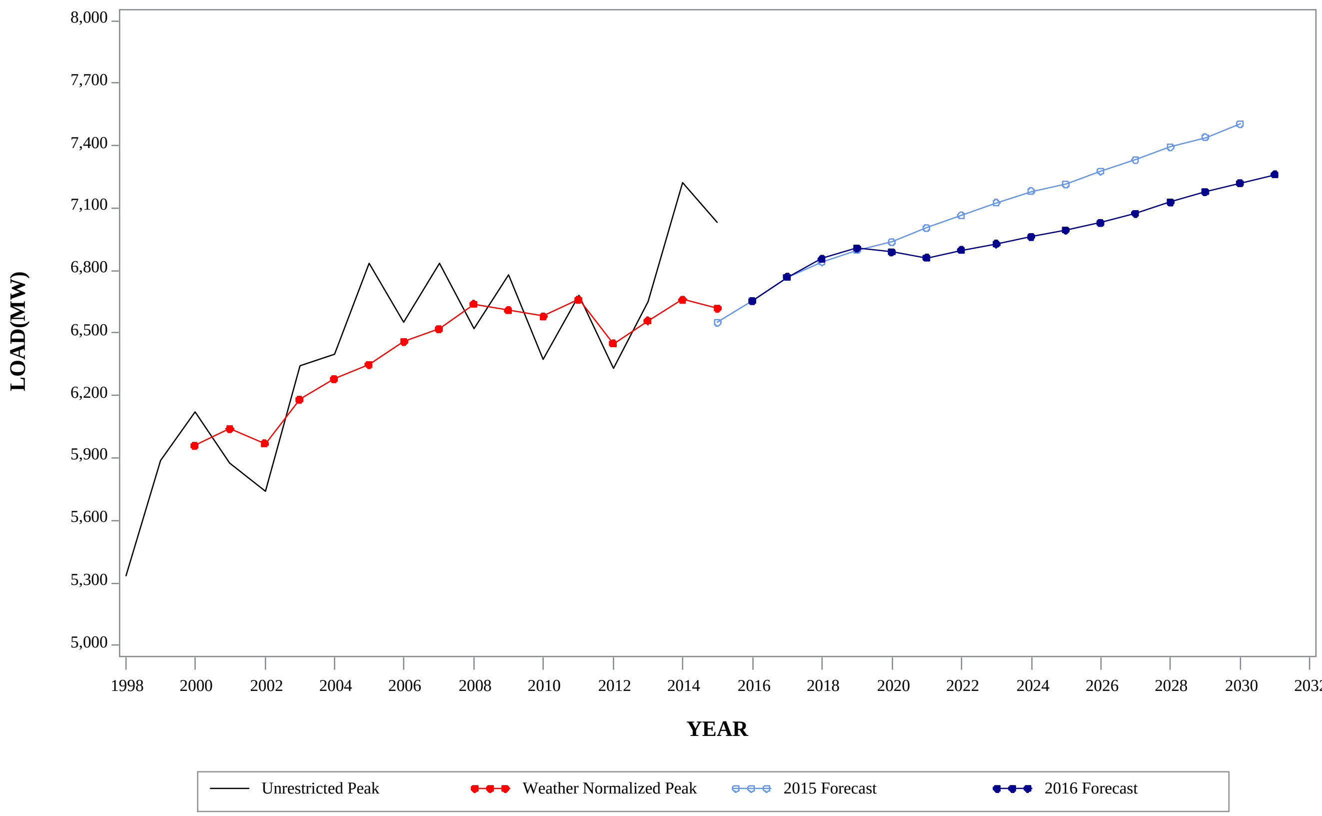
WINTER PEAK DEMAND FOR METED GEOGRAPHIC ZONE



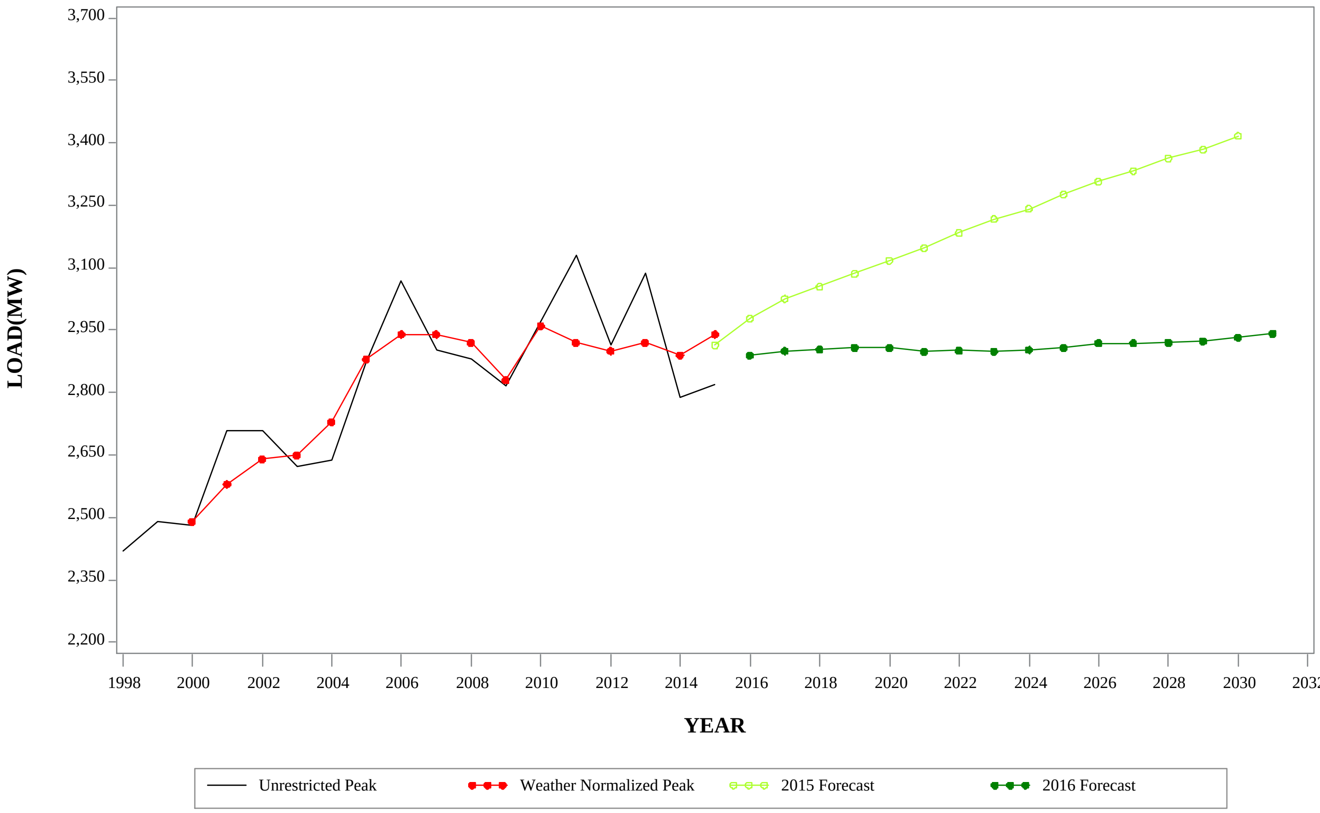
SUMMER PEAK DEMAND FOR PECO GEOGRAPHIC ZONE



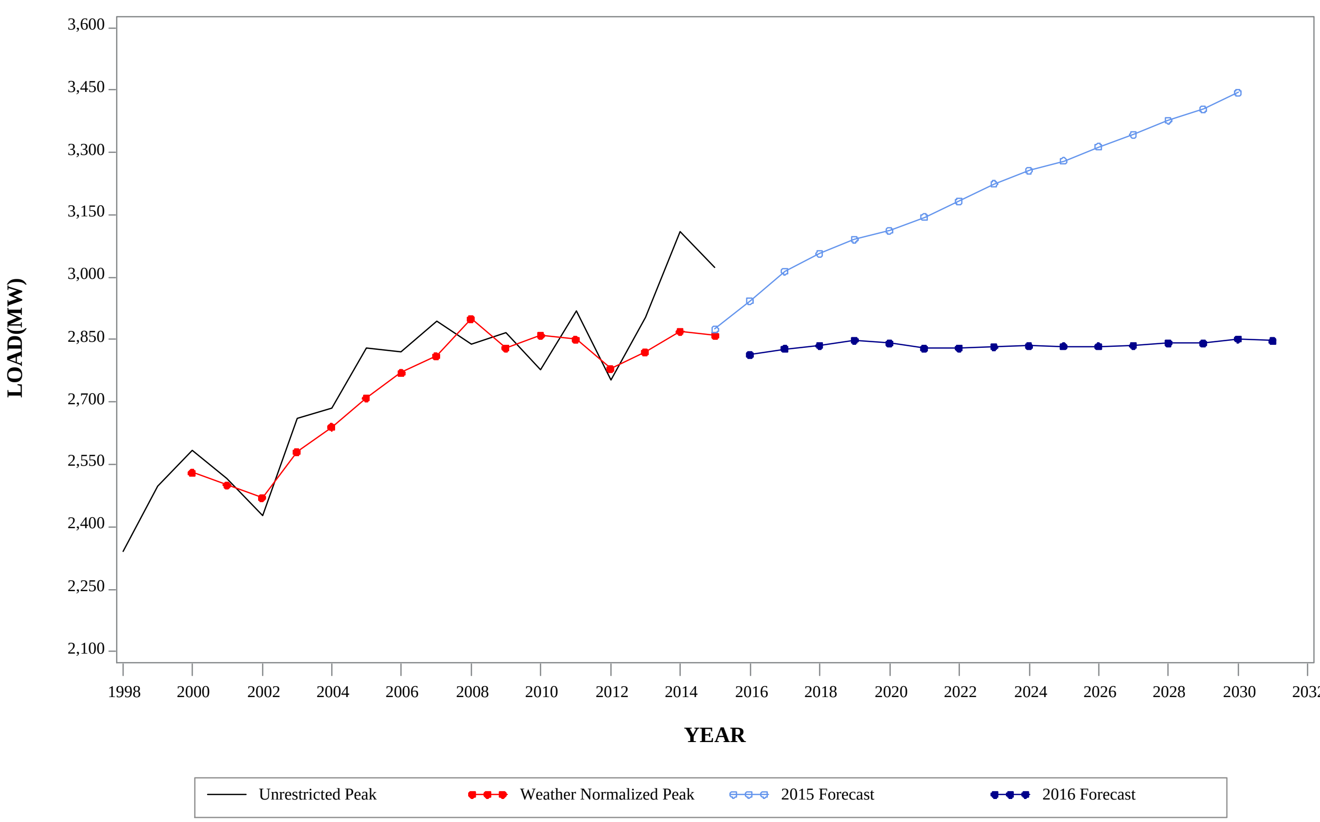
WINTER PEAK DEMAND FOR PECO GEOGRAPHIC ZONE



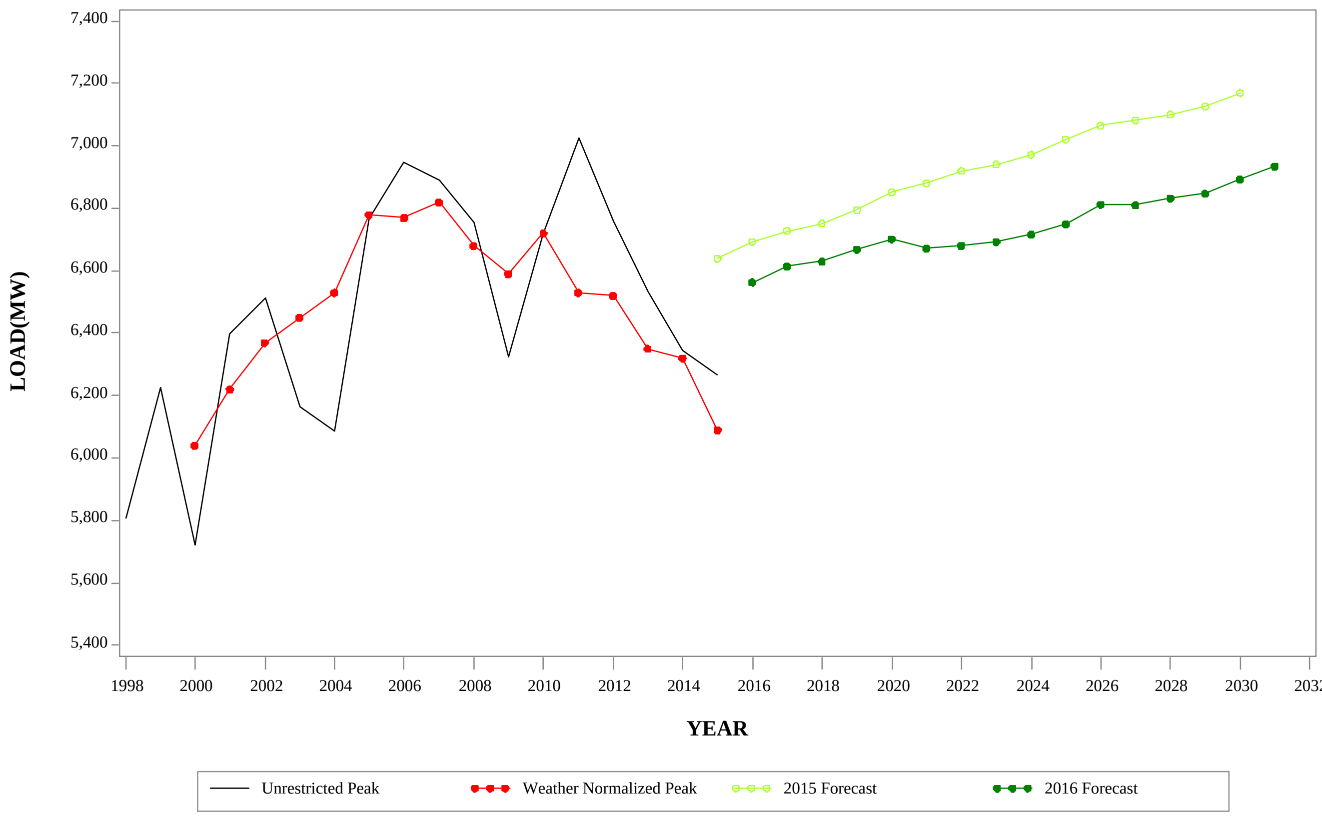
SUMMER PEAK DEMAND FOR PENLC GEOGRAPHIC ZONE



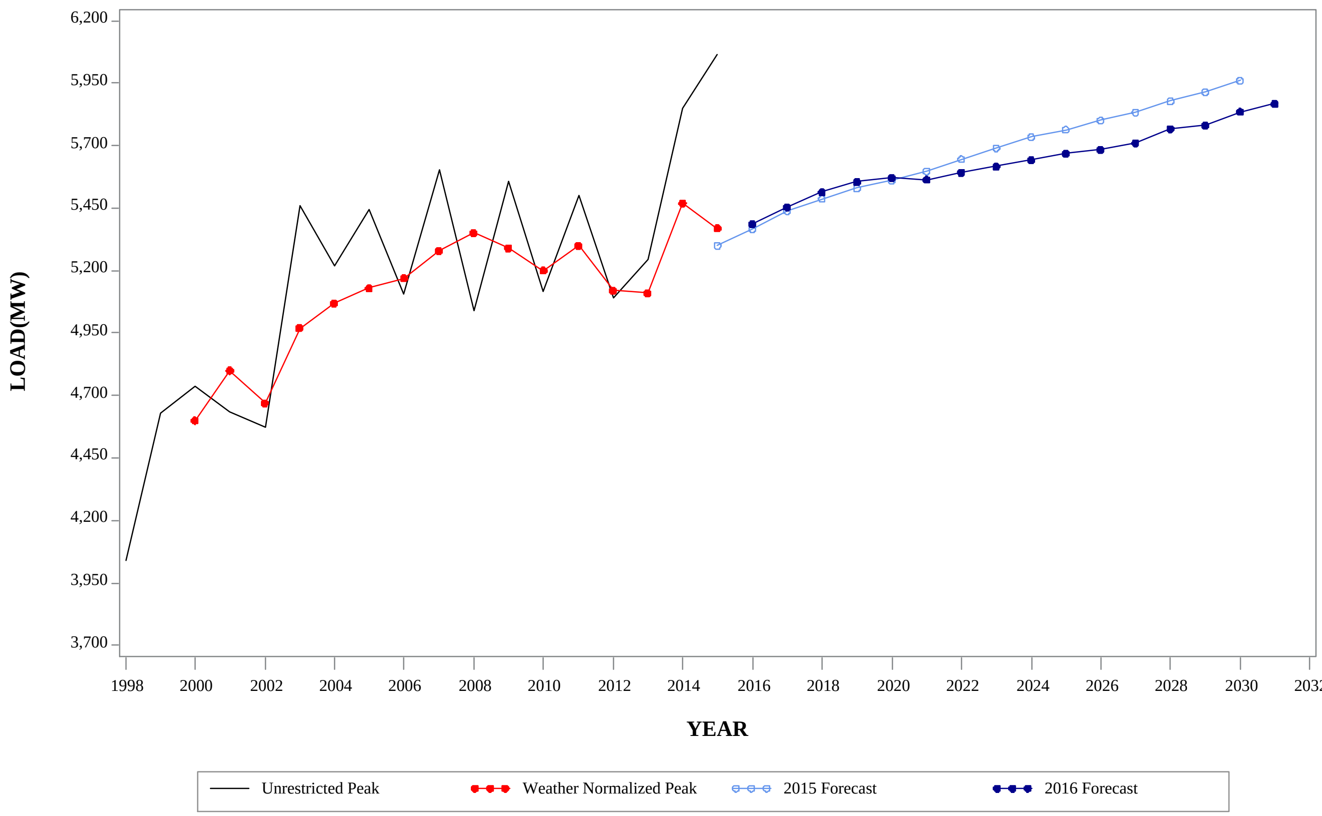
WINTER PEAK DEMAND FOR PENLC GEOGRAPHIC ZONE

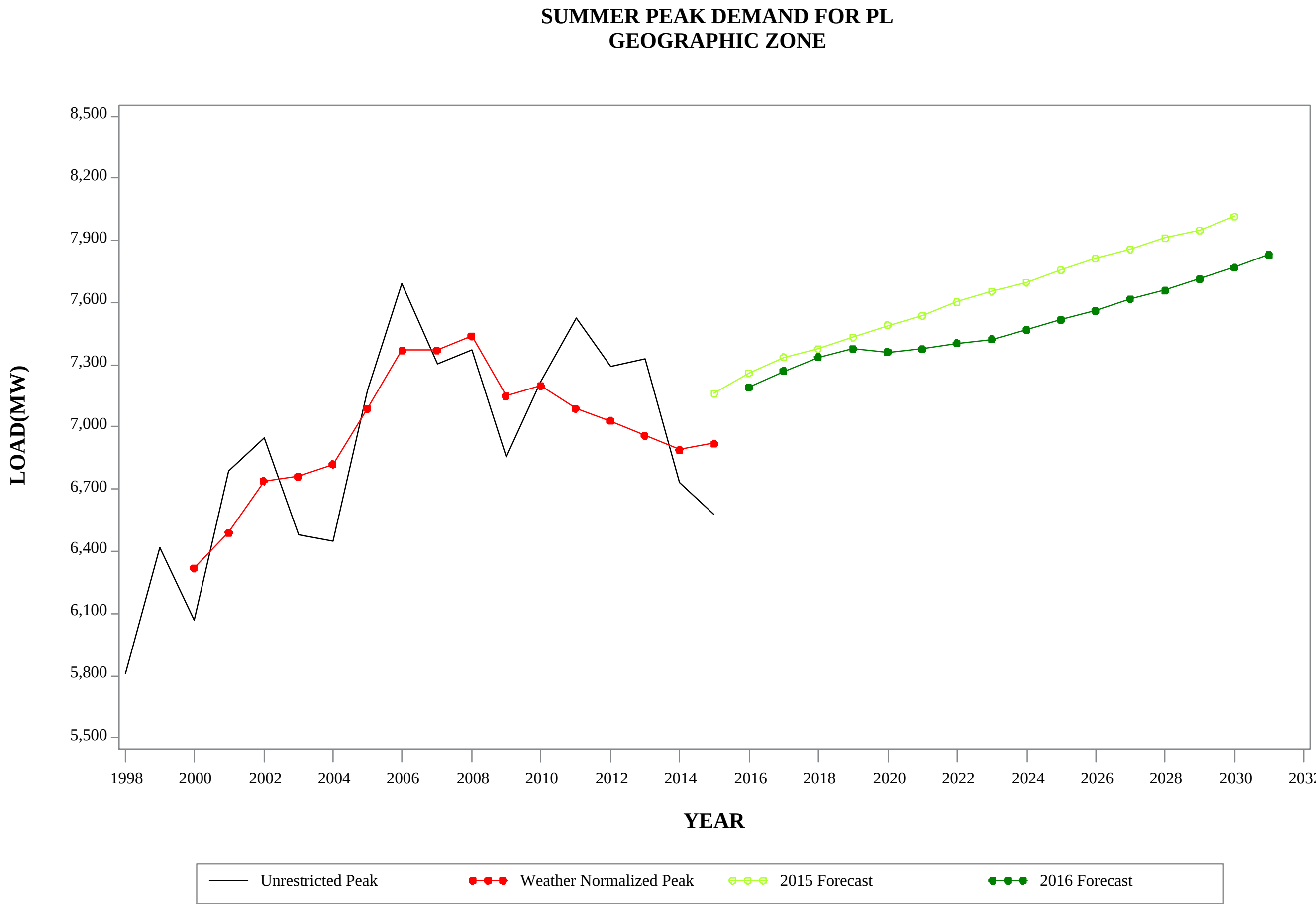


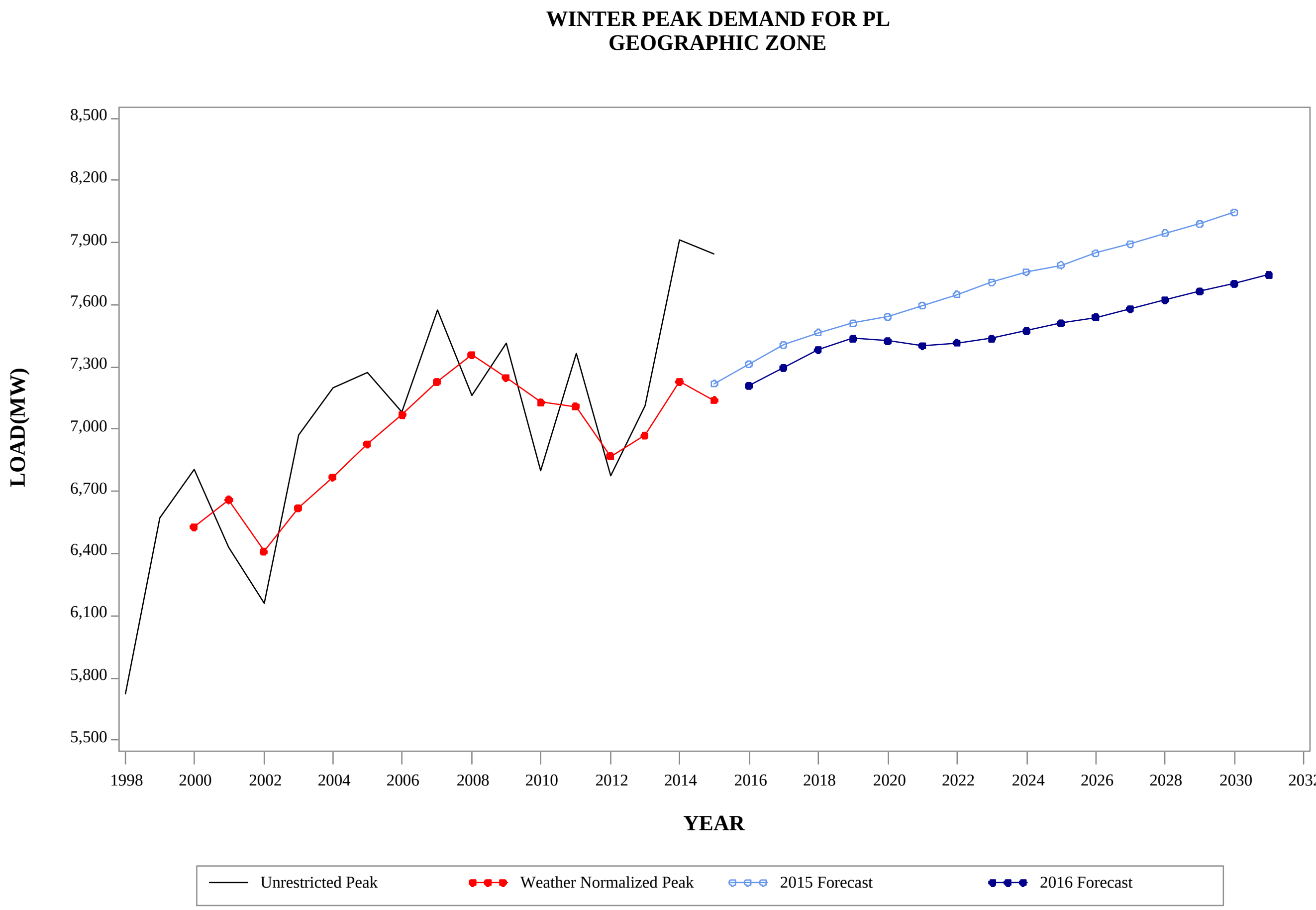
SUMMER PEAK DEMAND FOR PEPCO
GEOGRAPHIC ZONE

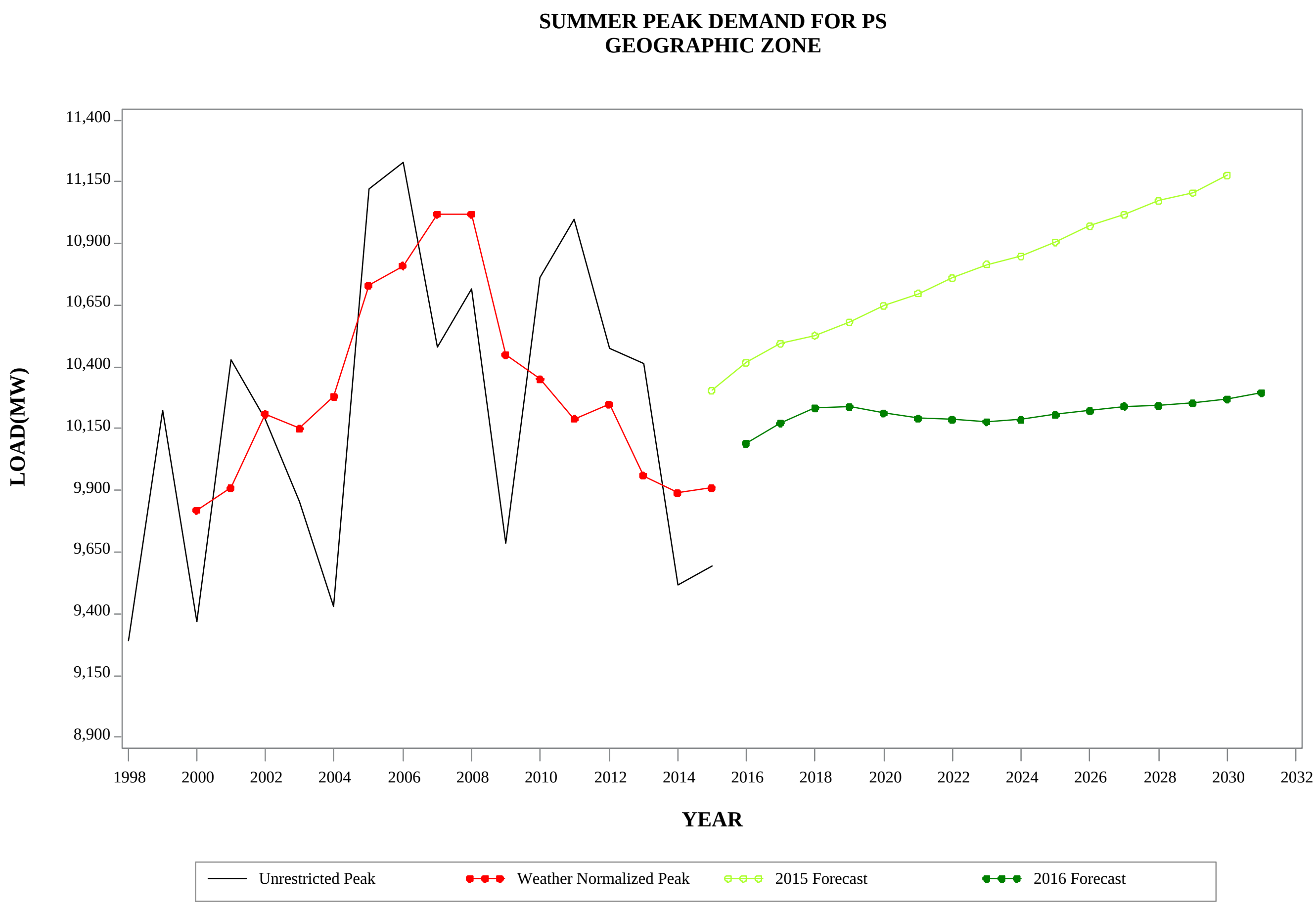


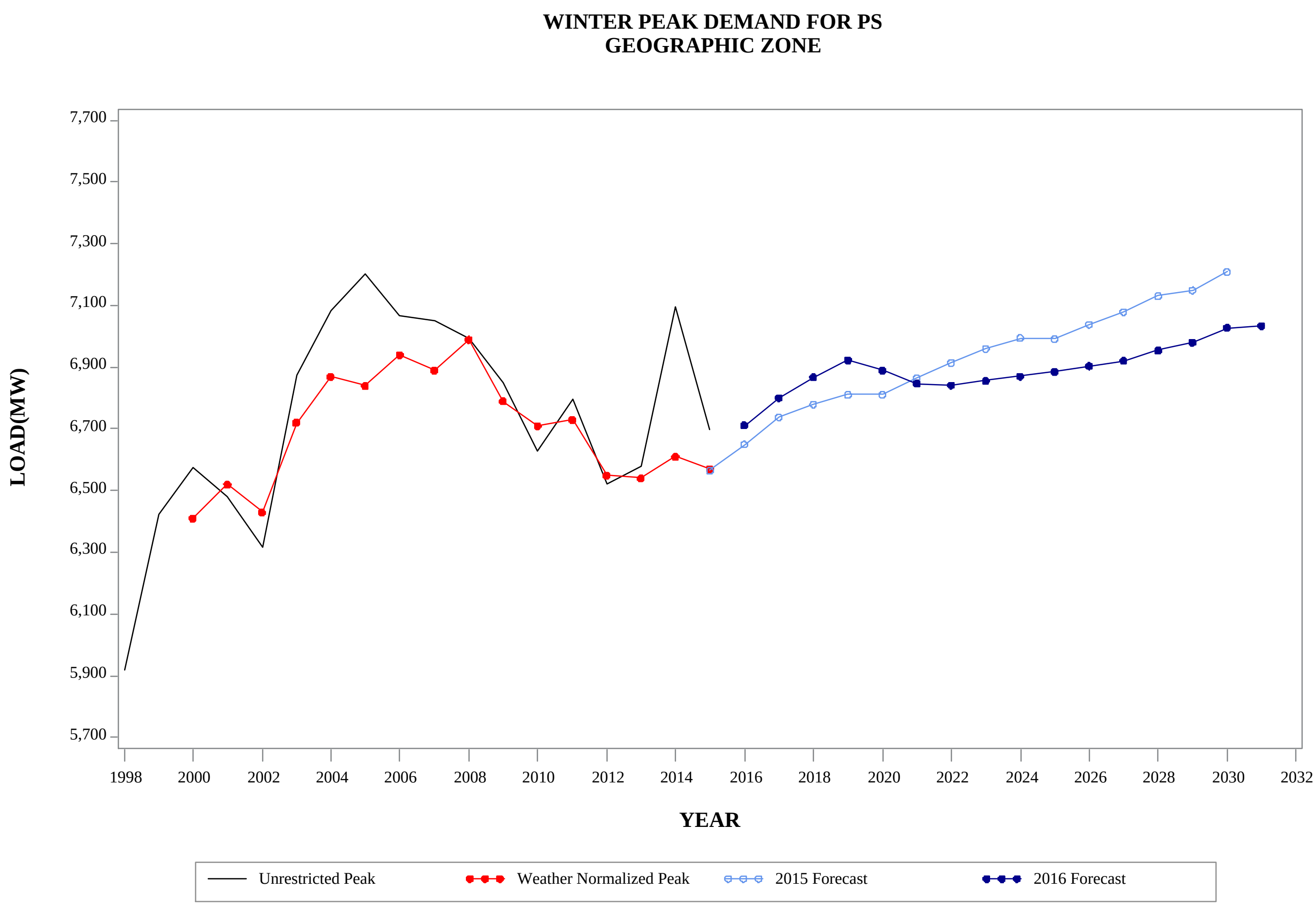
WINTER PEAK DEMAND FOR PEPCO
GEOGRAPHIC ZONE

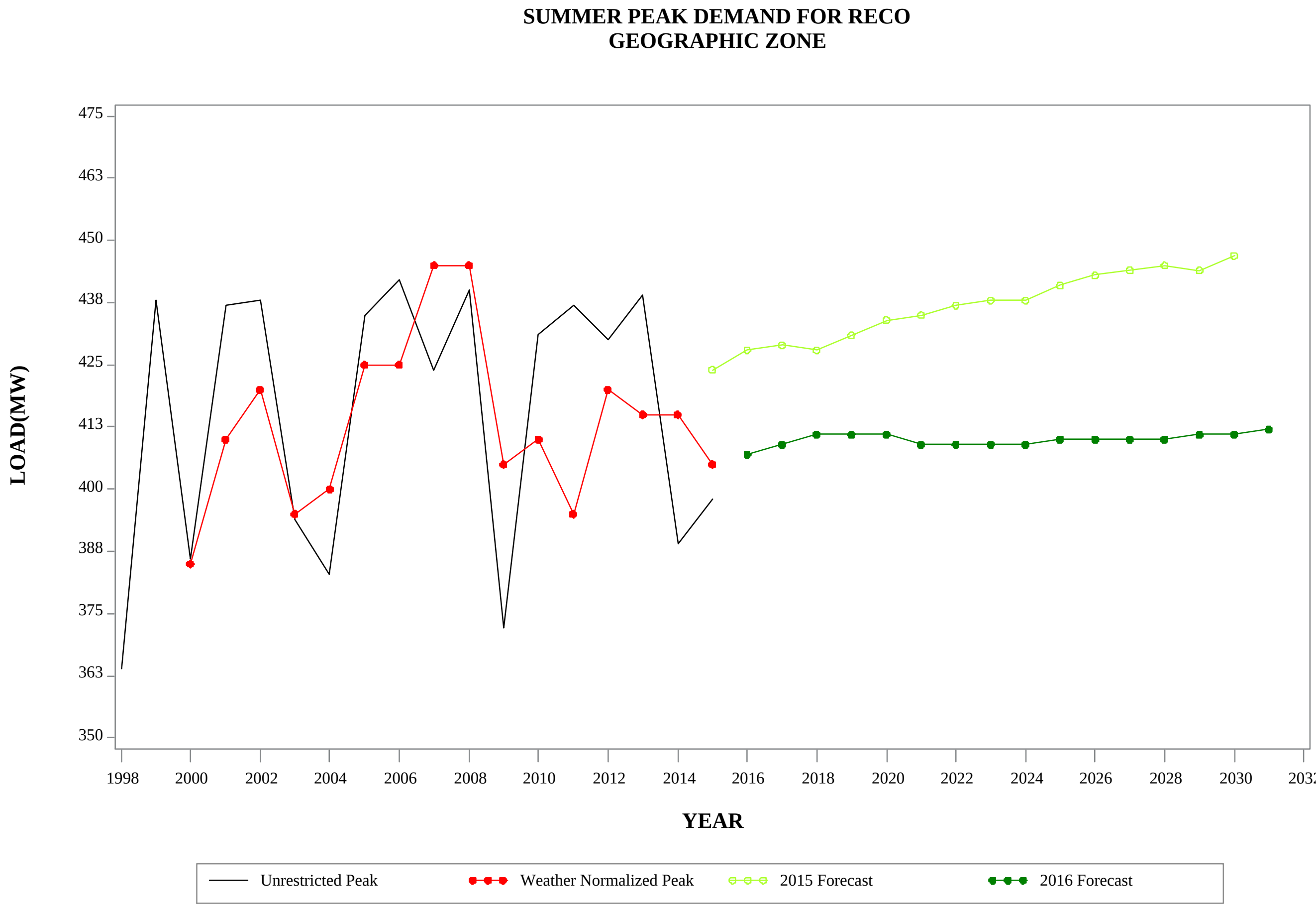


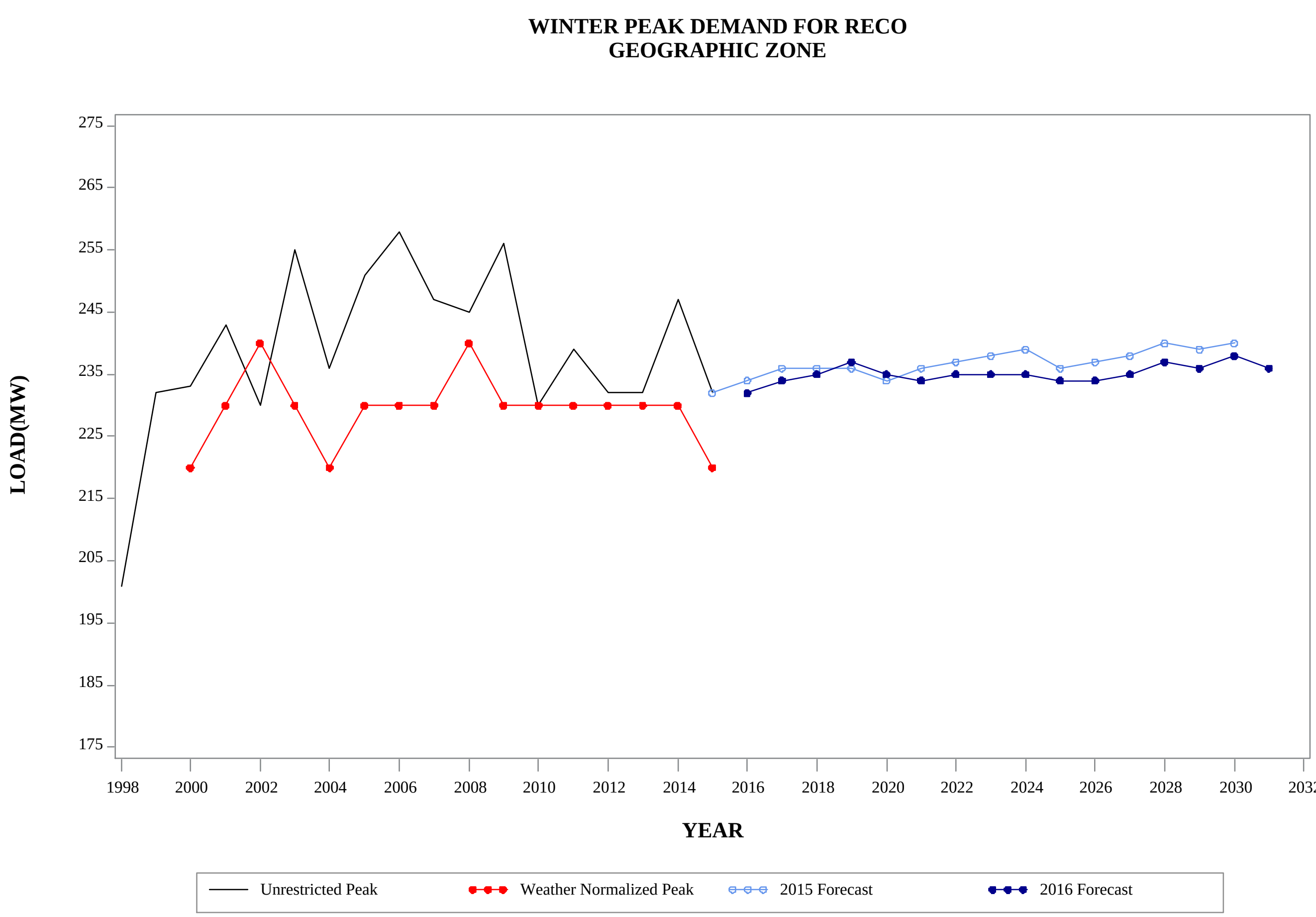

SUMMER PEAK DEMAND FOR PL
GEOGRAPHIC ZONE
LOAD(MW)
8,500
8,200
7,900
7,600
7,300
7,000
6,700
6,400
6,100
5,800
5,500
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
YEAR
Unrestricted Peak
Weather Normalized Peak
2015 Forecast
2016 Forecast


WINTER PEAK DEMAND FOR PL
GEOGRAPHIC ZONE
LOAD(MW)
8,500
8,200
7,900
7,600
7,300
7,000
6,700
6,400
6,100
5,800
5,500
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
YEAR
Unrestricted Peak
Weather Normalized Peak
2015 Forecast
2016 Forecast

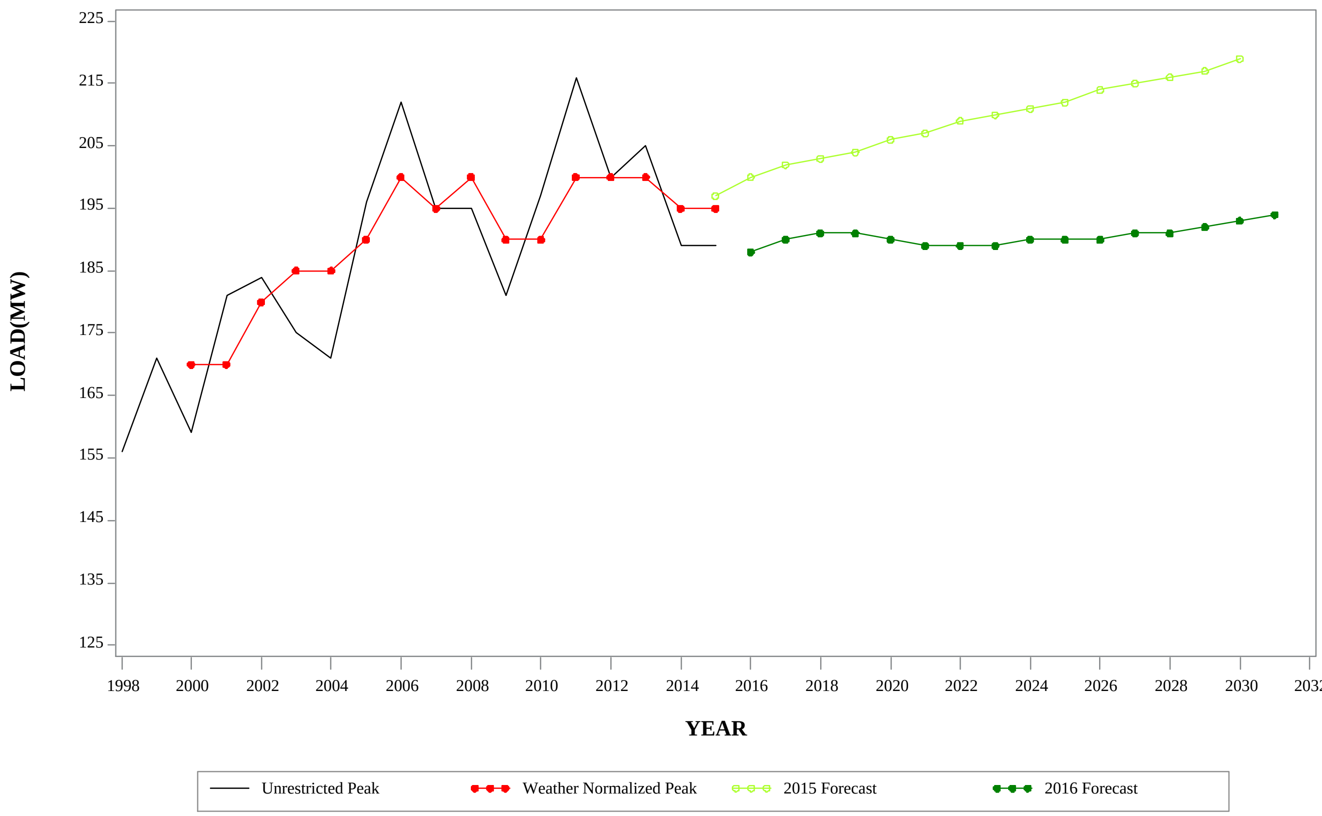

SUMMER PEAK DEMAND FOR PS
GEOGRAPHIC ZONE
LOAD(MW)
11,400
11,150
10,900
10,650
10,400
10,150
9,900
9,650
9,400
9,150
8,900
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
YEAR
Unrestricted Peak
Weather Normalized Peak
2015 Forecast
2016 Forecast


WINTER PEAK DEMAND FOR PS
GEOGRAPHIC ZONE
LOAD(MW)
7,700
7,500
7,300
7,100
6,900
6,700
6,500
6,300
6,100
5,900
5,700
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
YEAR
Unrestricted Peak
Weather Normalized Peak
2015 Forecast
2016 Forecast

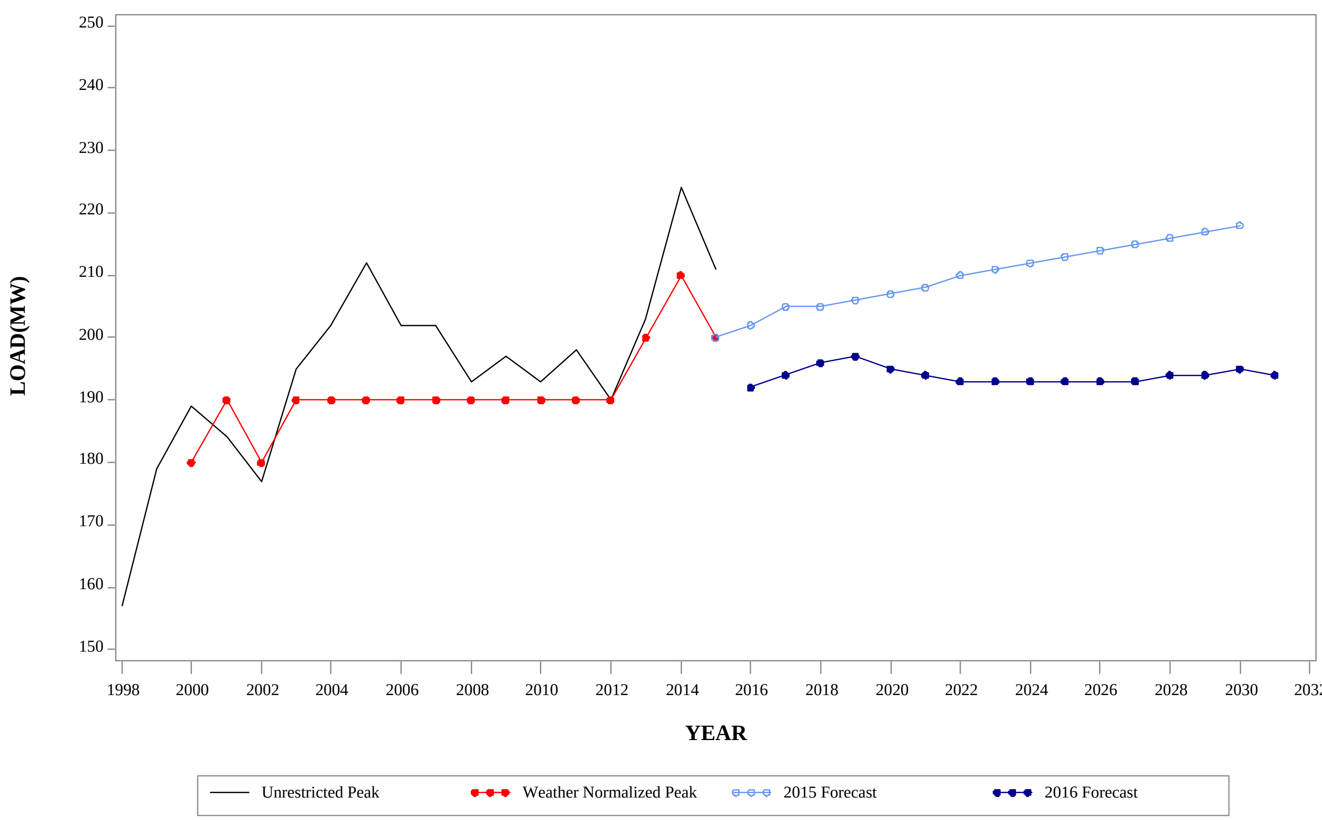

SUMMER PEAK DEMAND FOR RECO
GEOGRAPHIC ZONE
LOAD(MW)
475
463
450
438
425
413
400
388
375
363
350
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
YEAR
Unrestricted Peak
Weather Normalized Peak
2015 Forecast
2016 Forecast


WINTER PEAK DEMAND FOR RECO
GEOGRAPHIC ZONE
LOAD(MW)
275
265
255
245
235
225
215
205
195
185
175
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
YEAR
Unrestricted Peak
Weather Normalized Peak
2015 Forecast
2016 Forecast

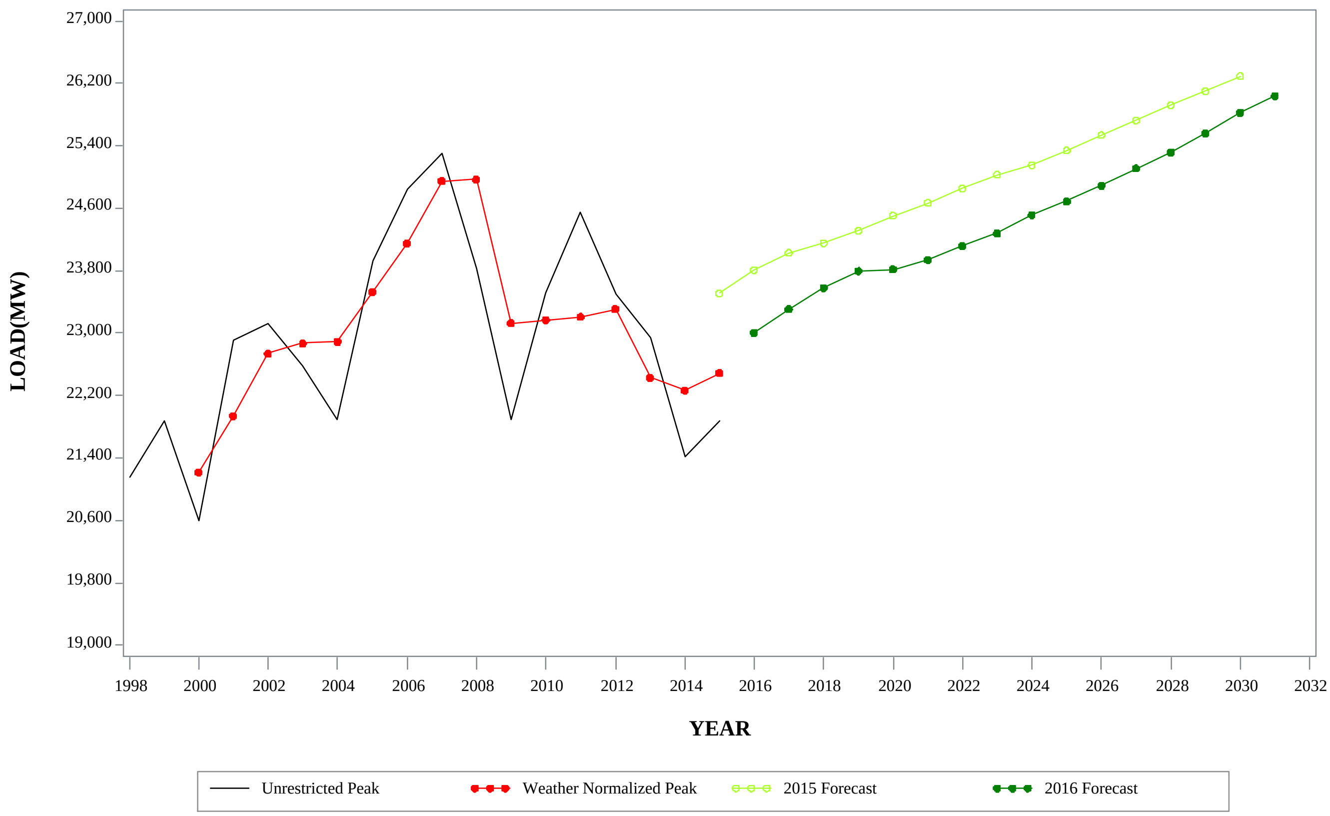
SUMMER PEAK DEMAND FOR UGI GEOGRAPHIC ZONE



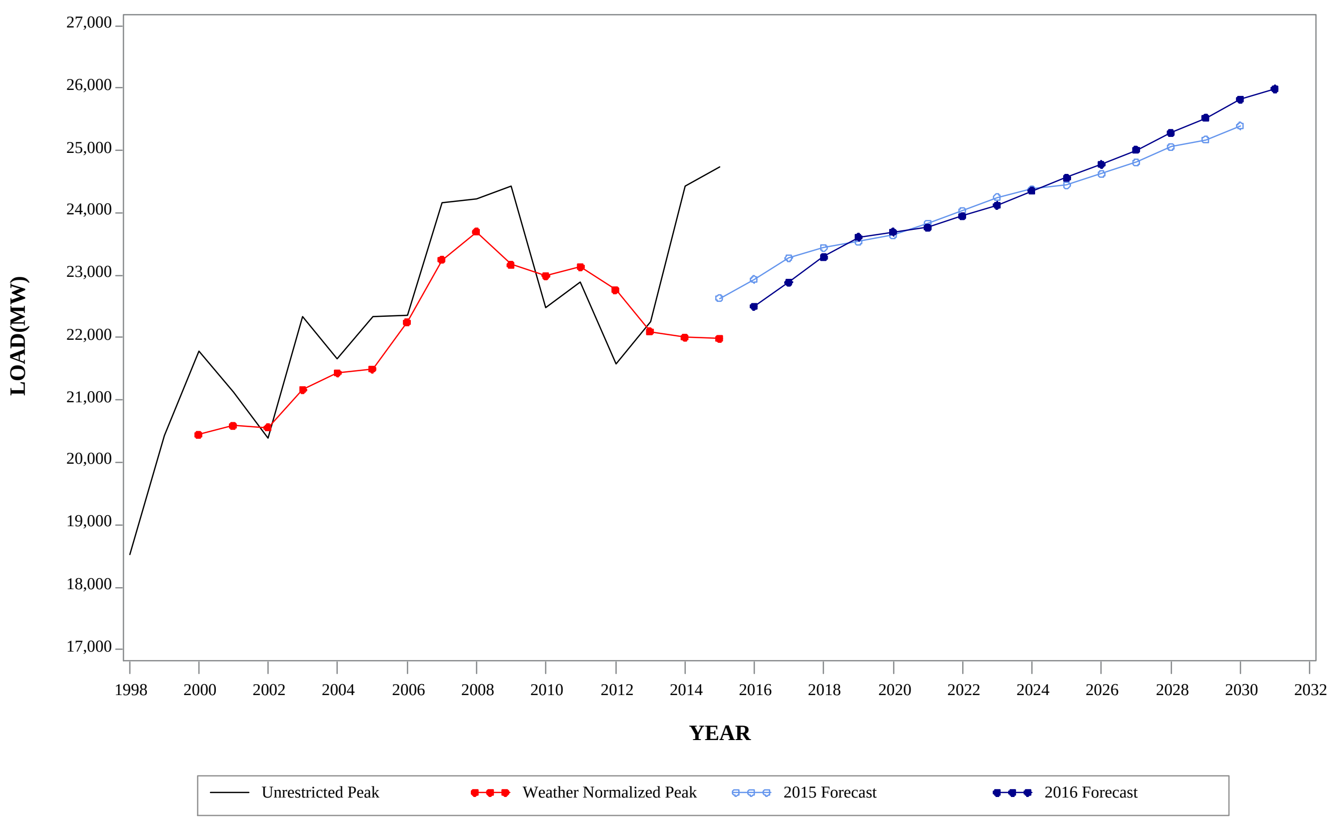
WINTER PEAK DEMAND FOR UGI GEOGRAPHIC ZONE

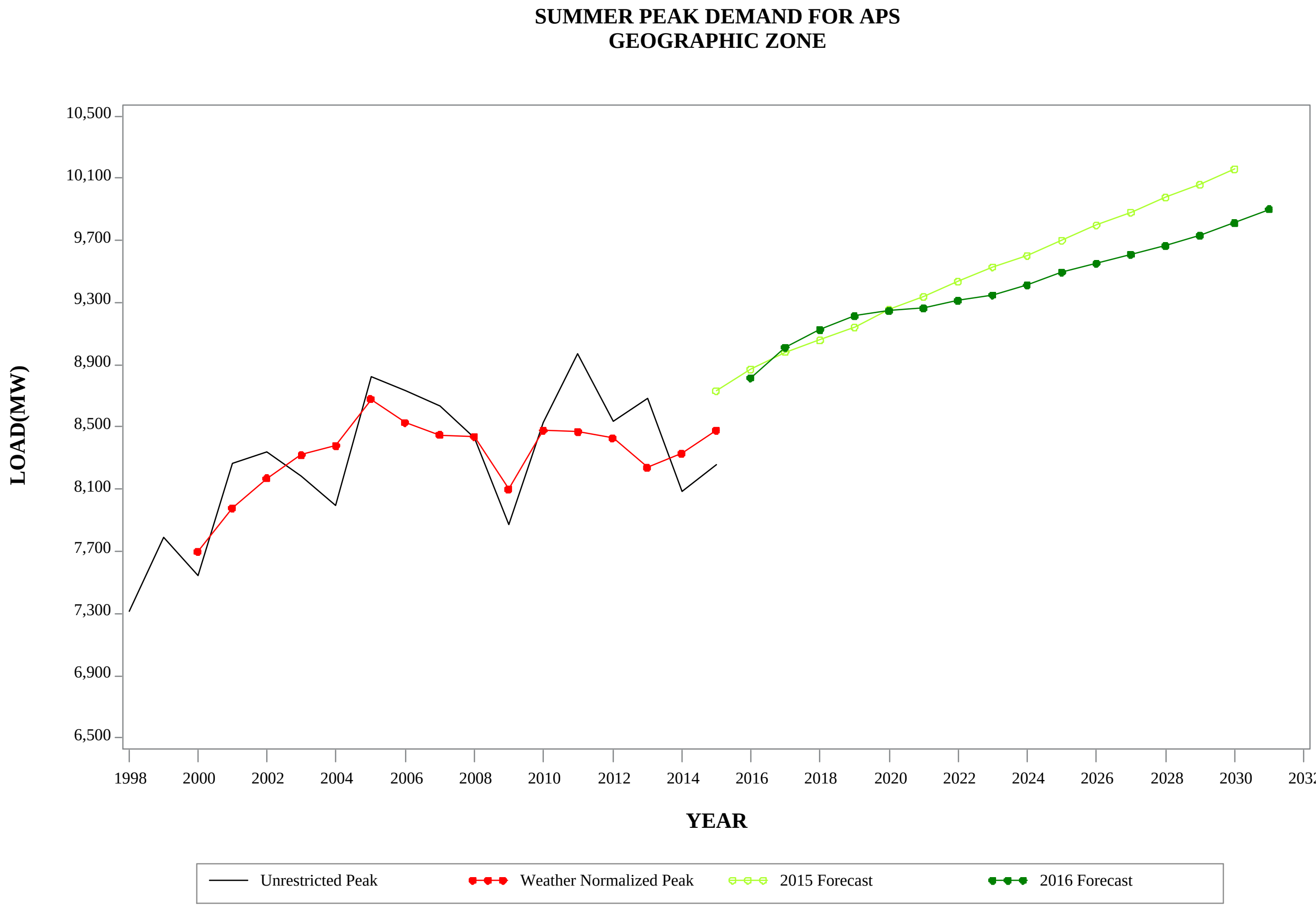


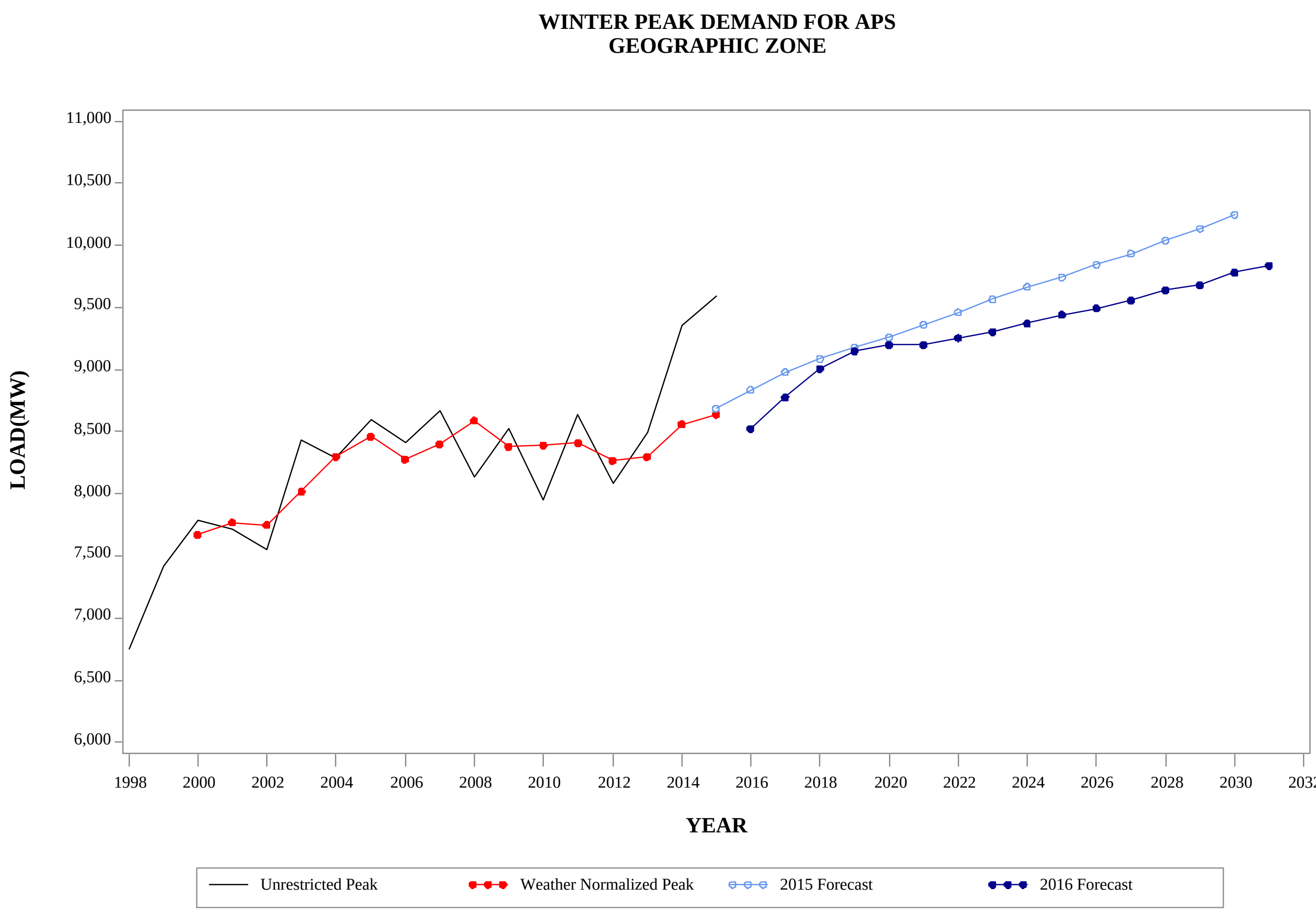
SUMMER PEAK DEMAND FOR AEP GEOGRAPHIC ZONE



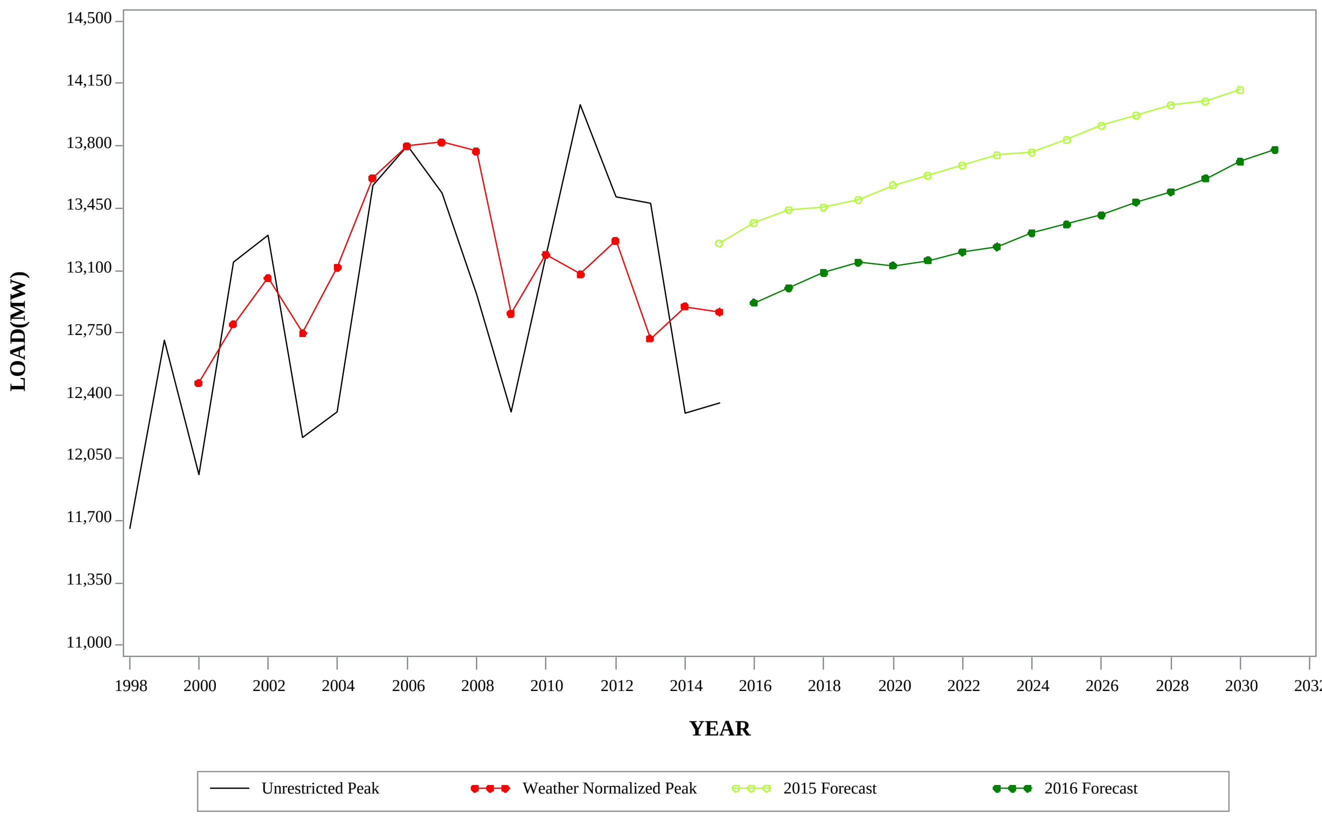
WINTER PEAK DEMAND FOR AEP GEOGRAPHIC ZONE



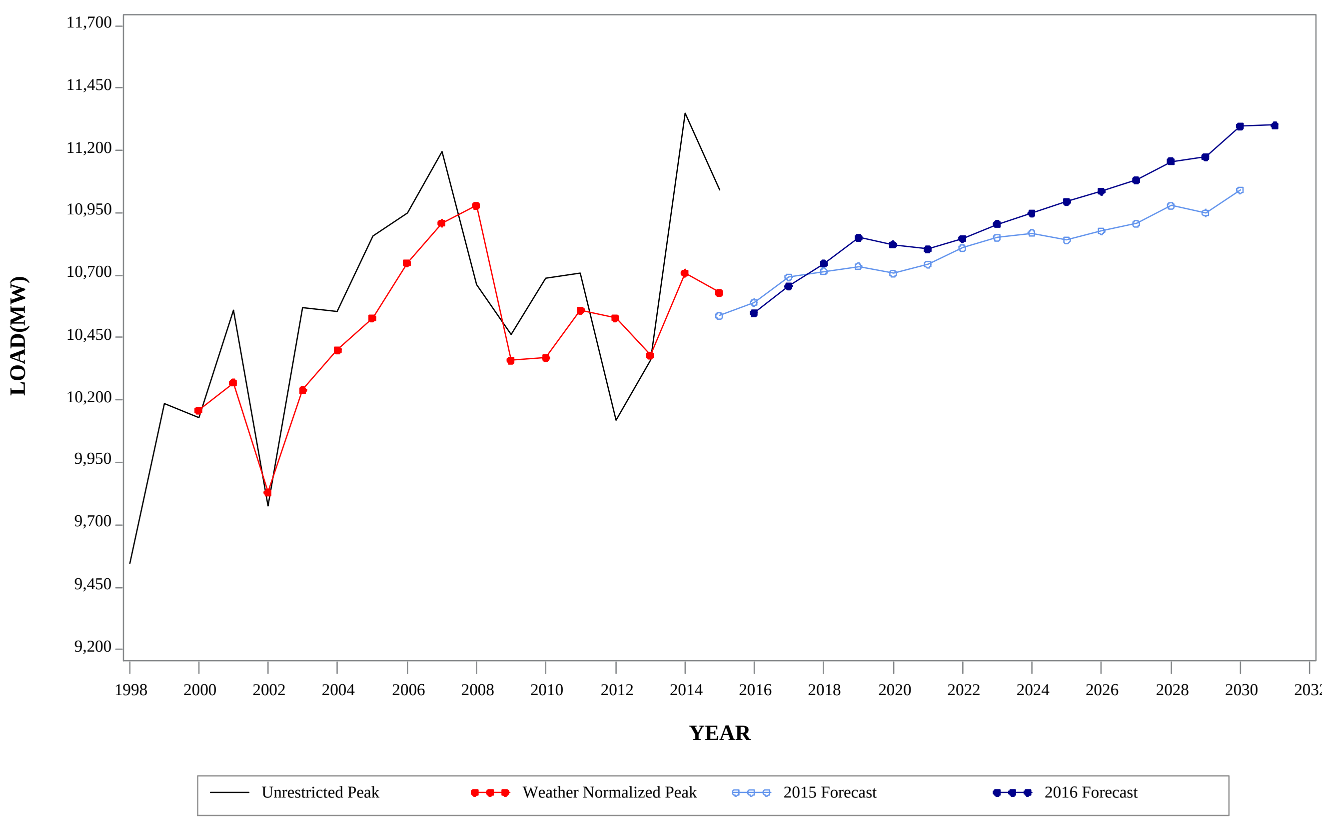

SUMMER PEAK DEMAND FOR APS
GEOGRAPHIC ZONE
LOAD(MW)
10,500
10,100
9,700
9,300
8,900
8,500
8,100
7,700
7,300
6,900
6,500
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
YEAR
Unrestricted Peak
Weather Normalized Peak
2015 Forecast
2016 Forecast


WINTER PEAK DEMAND FOR APS
GEOGRAPHIC ZONE
LOAD(MW)
11,000
10,500
10,000
9,500
9,000
8,500
8,000
7,500
7,000
6,500
6,000
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
YEAR
Unrestricted Peak
Weather Normalized Peak
2015 Forecast
2016 Forecast

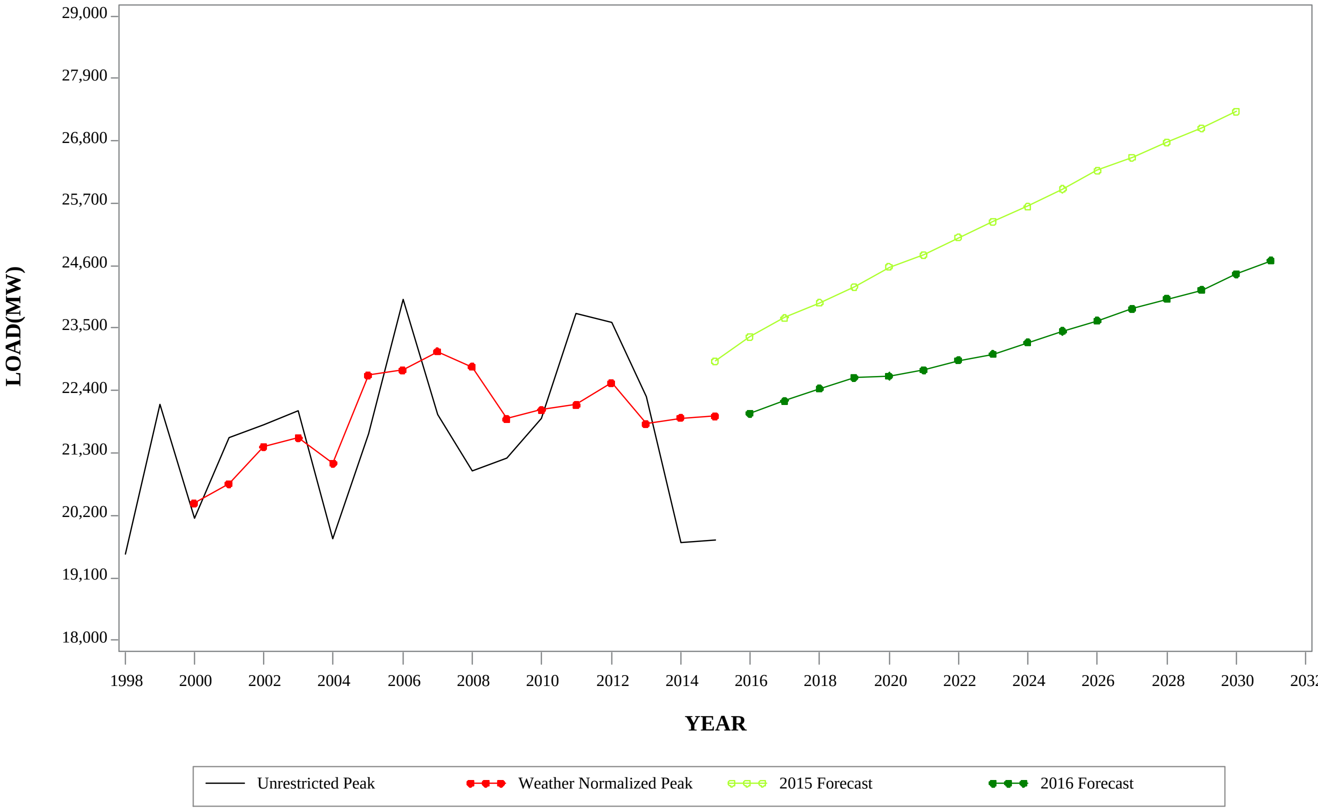
SUMMER PEAK DEMAND FOR ATSI GEOGRAPHIC ZONE



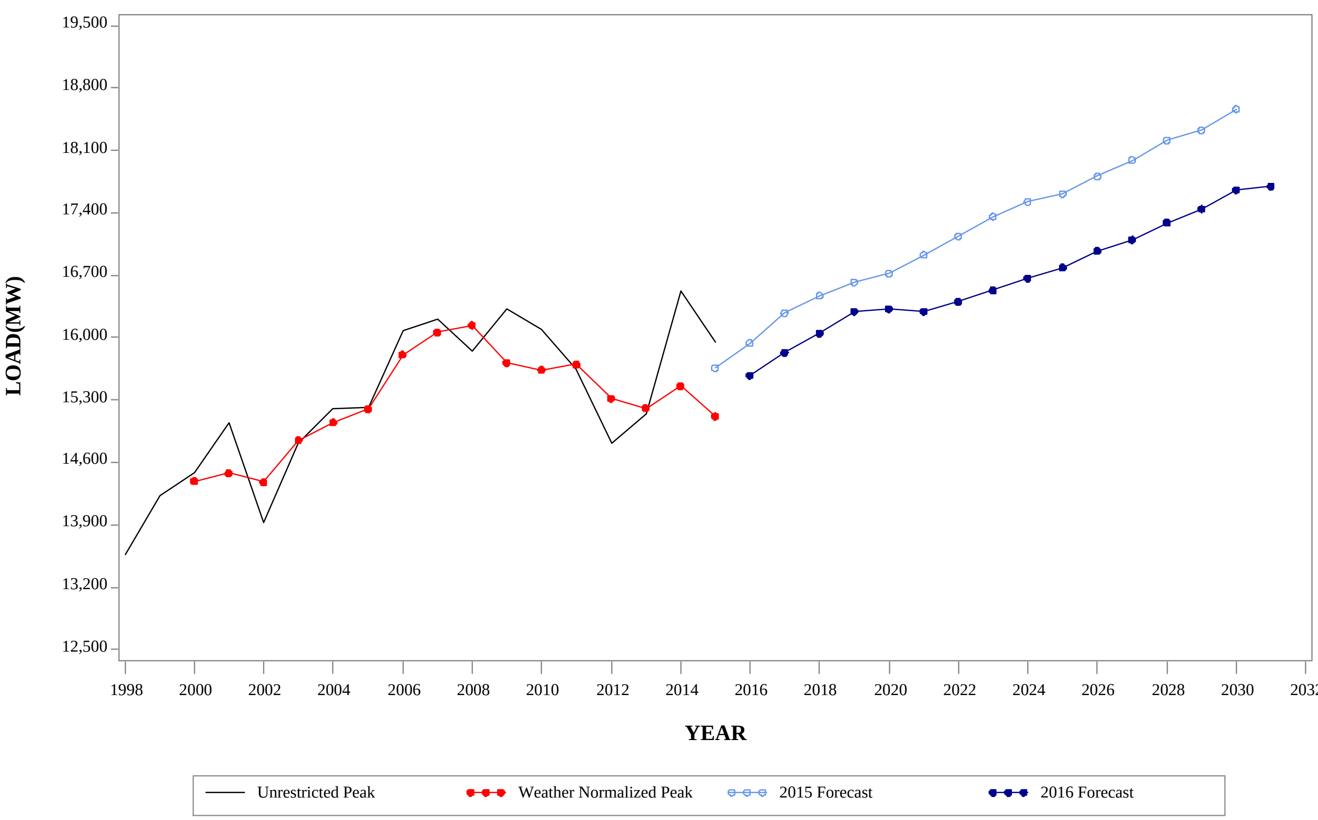
WINTER PEAK DEMAND FOR ATSI GEOGRAPHIC ZONE

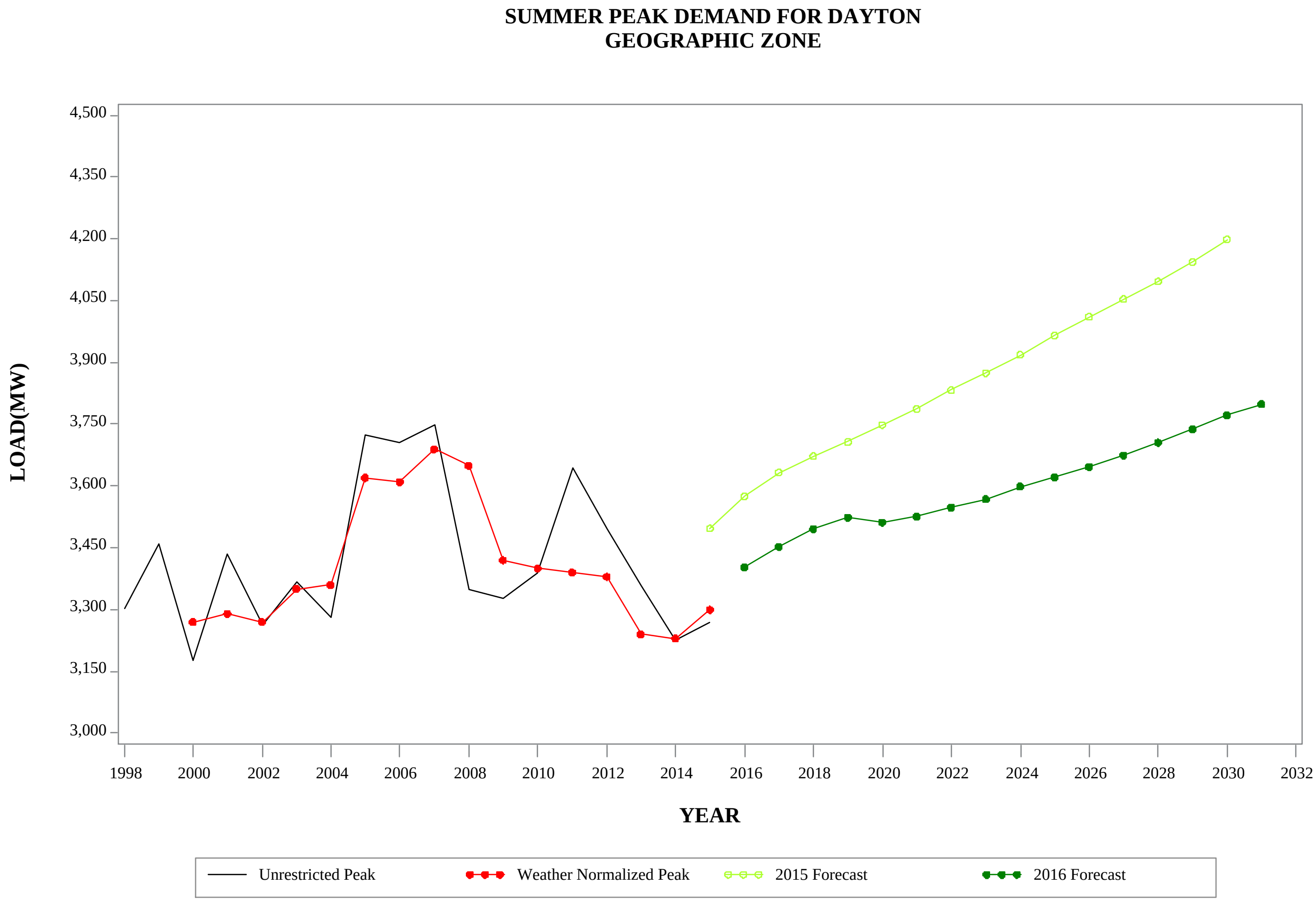


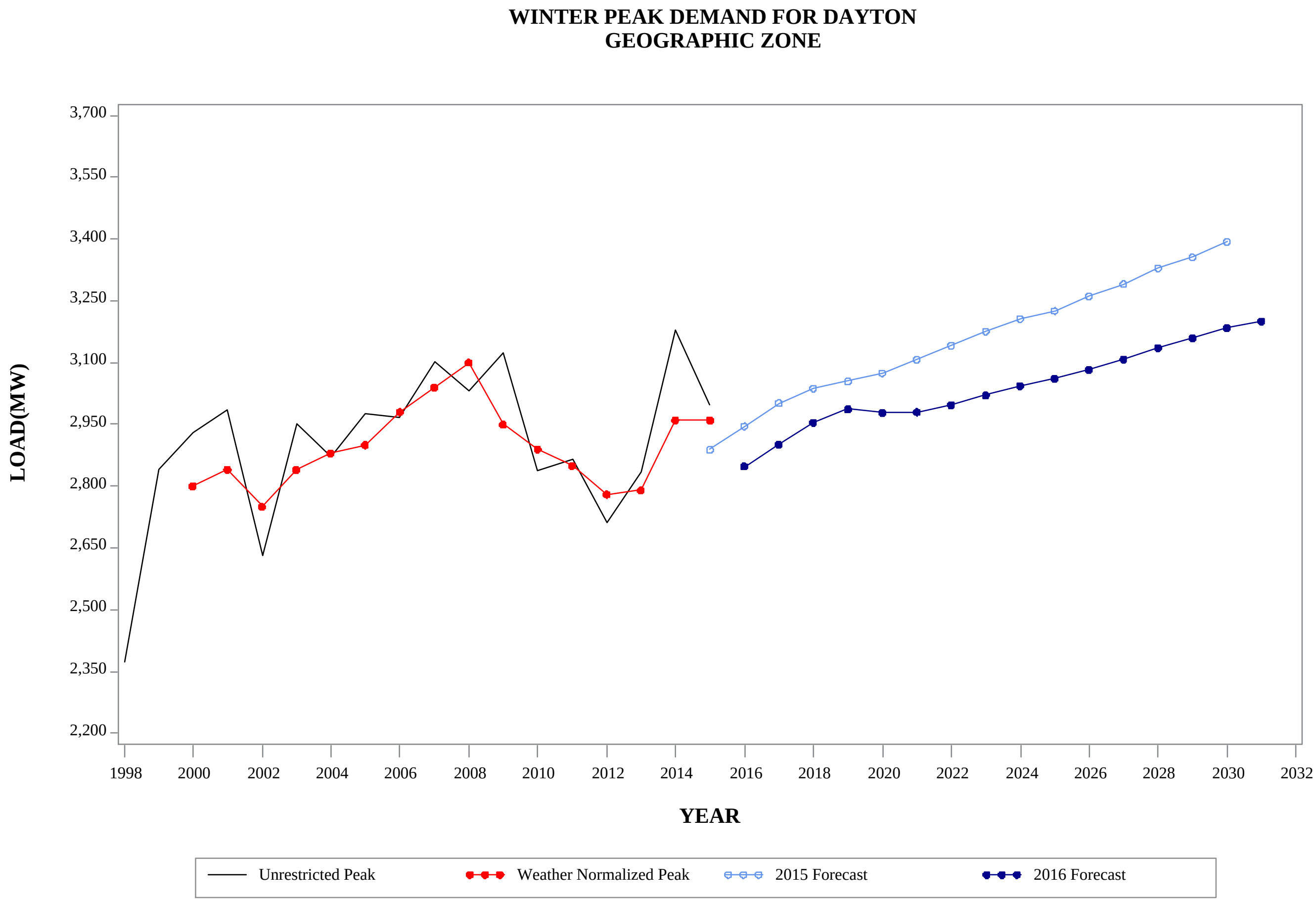
SUMMER PEAK DEMAND FOR COMED GEOGRAPHIC ZONE



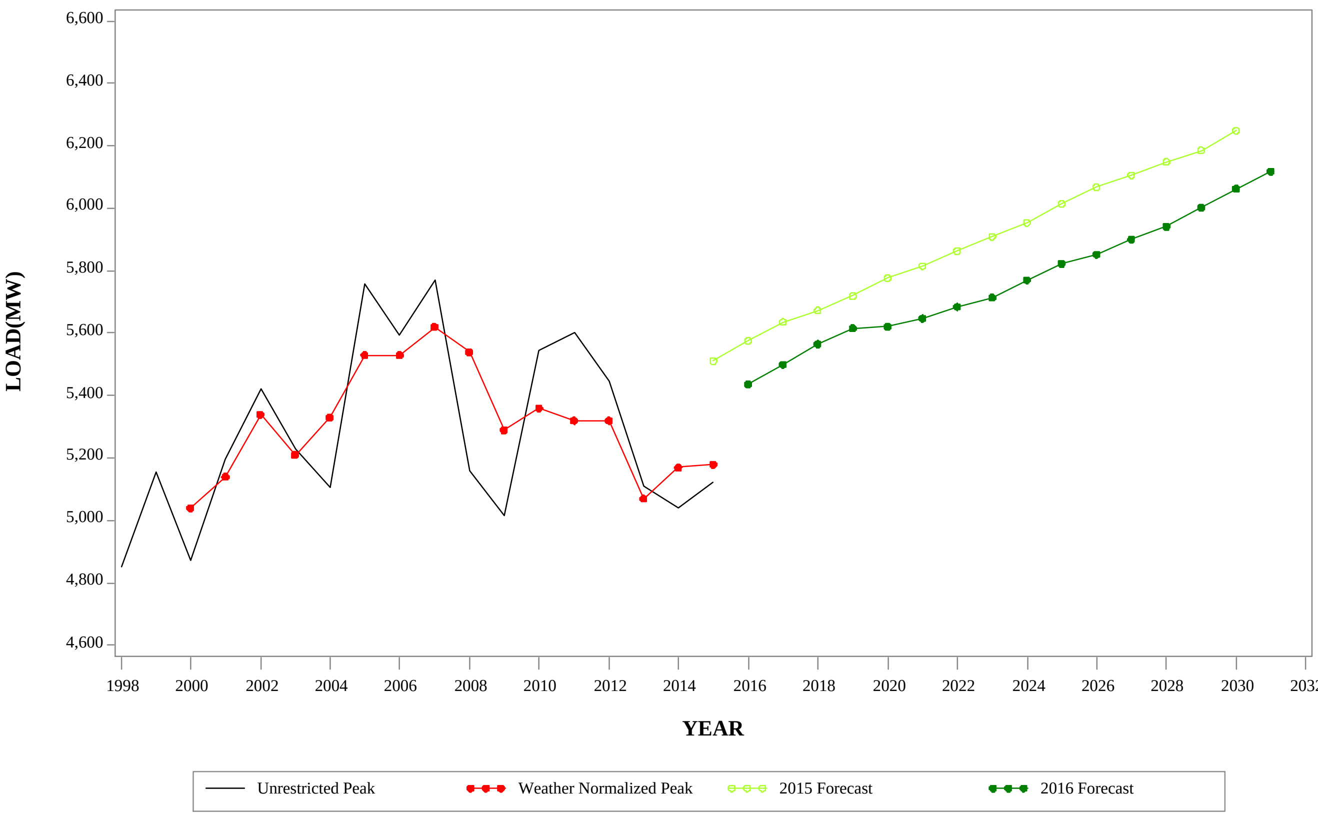
WINTER PEAK DEMAND FOR COMED GEOGRAPHIC ZONE



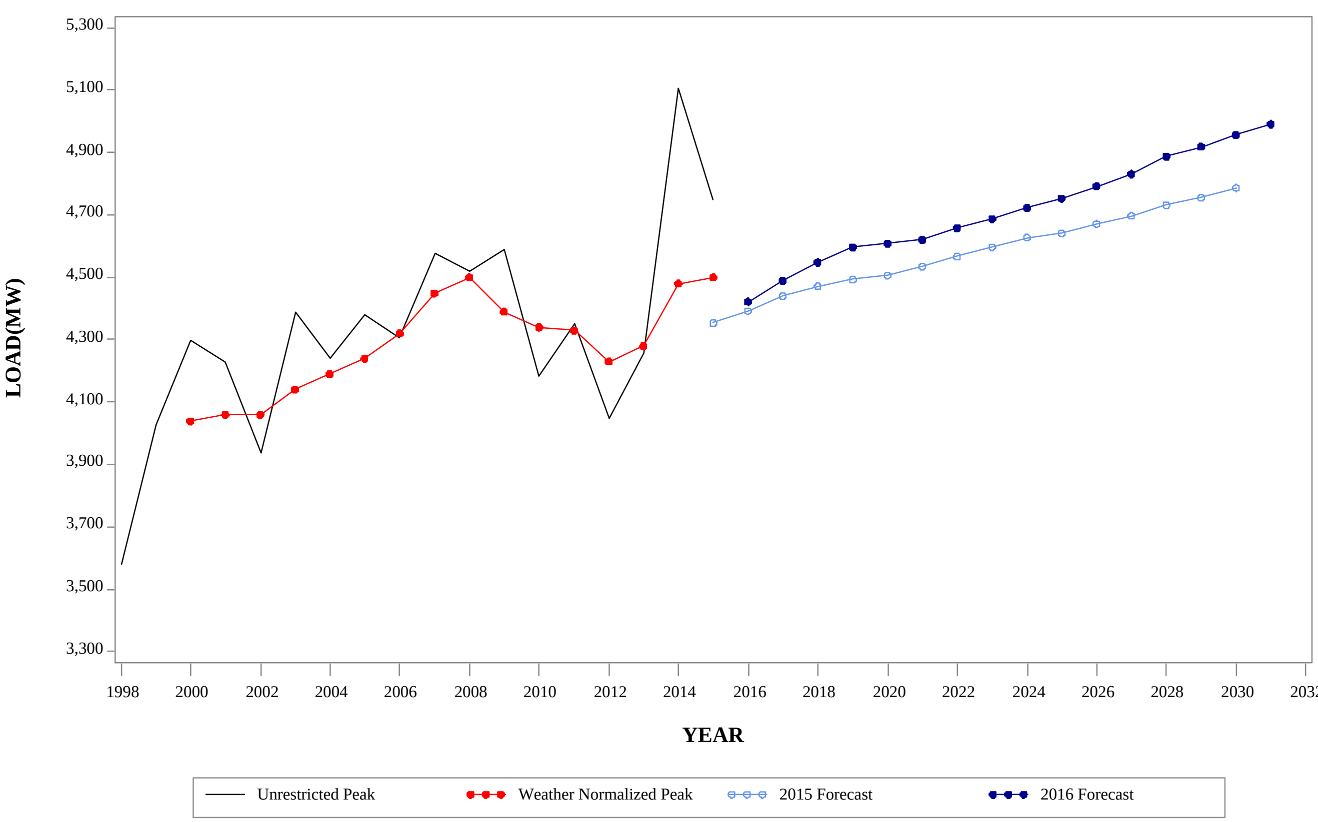

SUMMER PEAK DEMAND FOR DAYTON
GEOGRAPHIC ZONE
LOAD(MW)
4,500
4,350
4,200
4,050
3,900
3,750
3,600
3,450
3,300
3,150
3,000
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
YEAR
Unrestricted Peak
Weather Normalized Peak
2015 Forecast
2016 Forecast

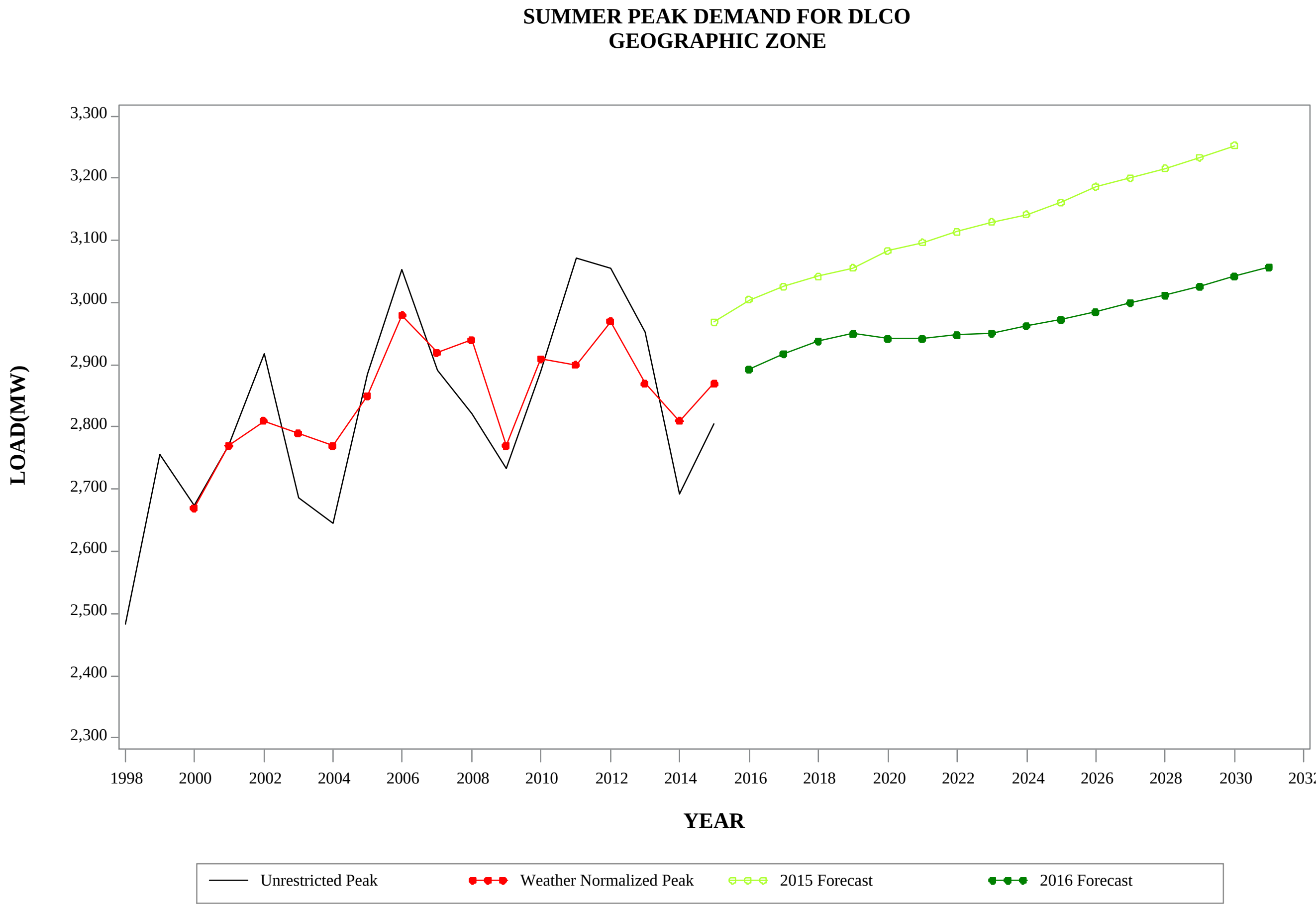

WINTER PEAK DEMAND FOR DAYTON
GEOGRAPHIC ZONE
LOAD(MW)
3,700
3,550
3,400
3,250
3,100
2,950
2,800
2,650
2,500
2,350
2,200
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
YEAR
Unrestricted Peak
Weather Normalized Peak
2015 Forecast
2016 Forecast

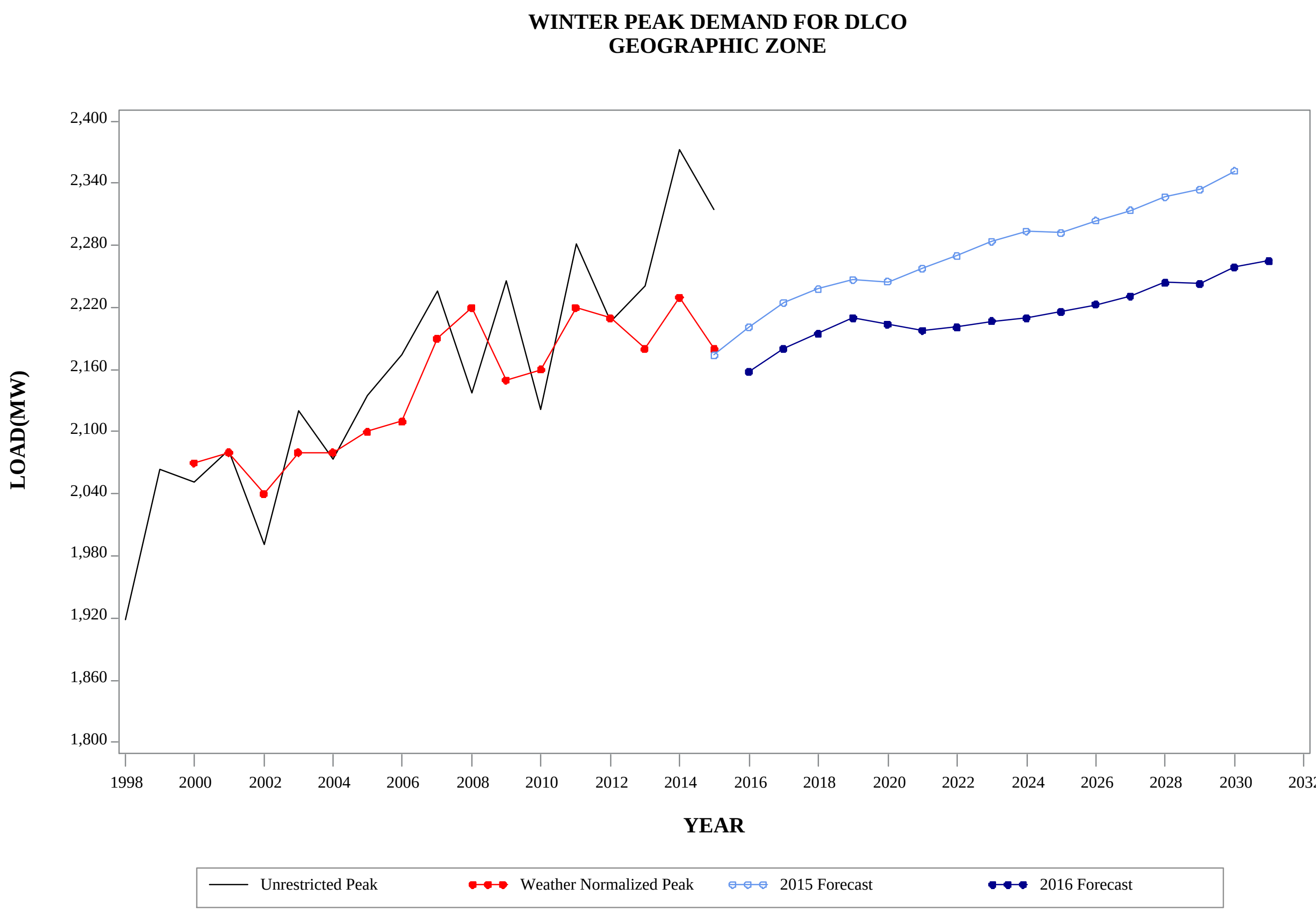
SUMMER PEAK DEMAND FOR DEOK
GEOGRAPHIC ZONE

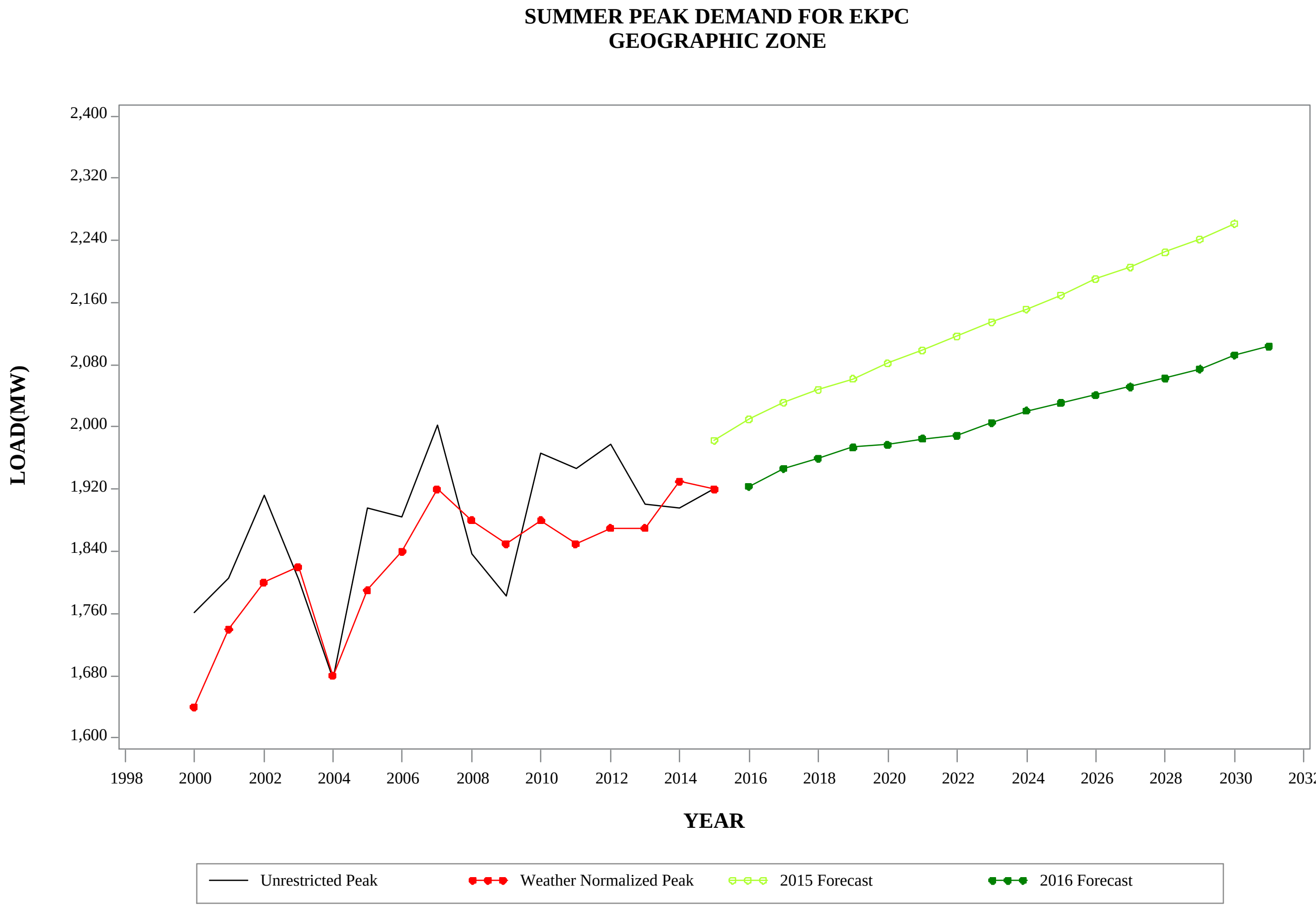


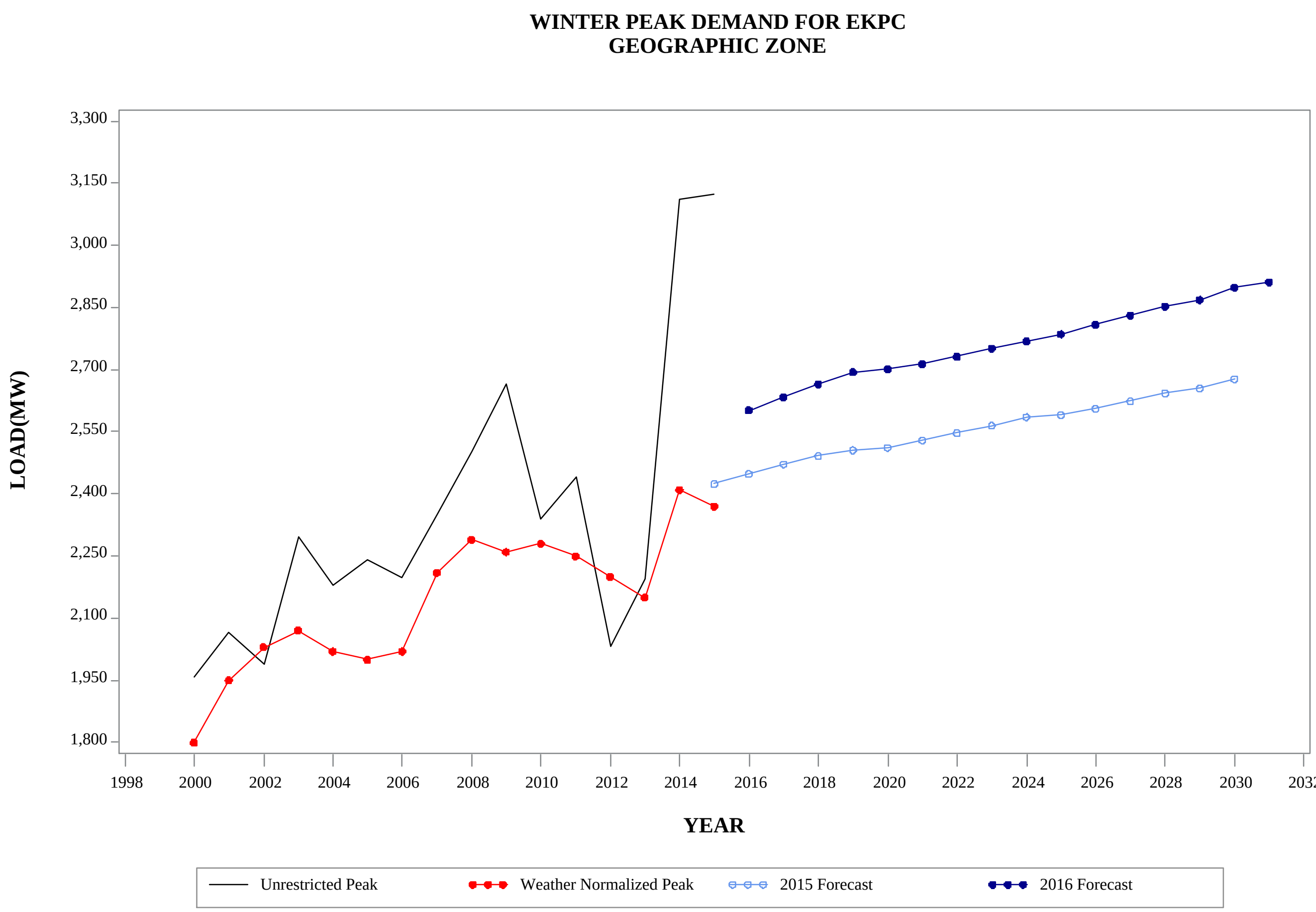
WINTER PEAK DEMAND FOR DEOK
GEOGRAPHIC ZONE



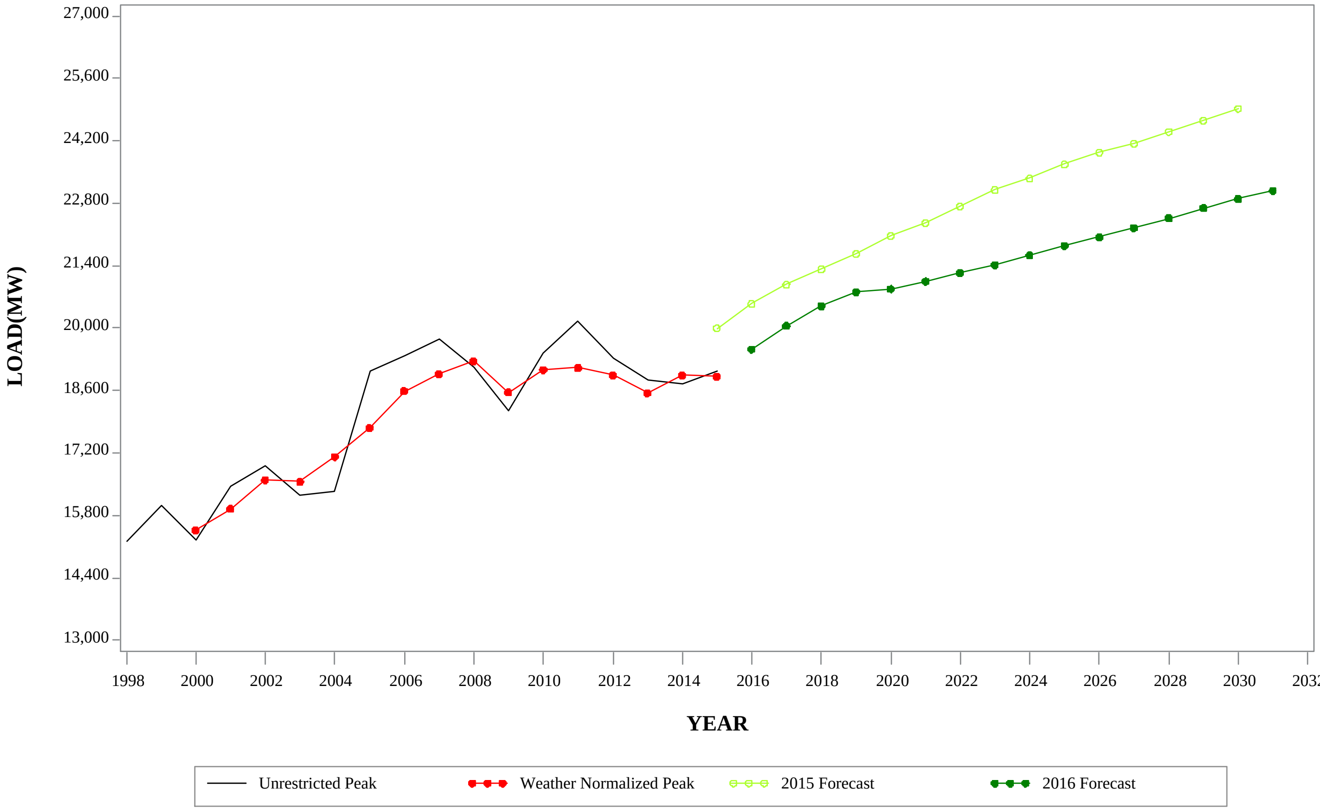

SUMMER PEAK DEMAND FOR DLCO
GEOGRAPHIC ZONE
LOAD(MW)
3,300
3,200
3,100
3,000
2,900
2,800
2,700
2,600
2,500
2,400
2,300
1998 2000 2002 2004 2006 2008 2010 2012 2014 2016 2018 2020 2022 2024 2026 2028 2030 2032
YEAR
Unrestricted Peak
Weather Normalized Peak
2015 Forecast
2016 Forecast


WINTER PEAK DEMAND FOR DLCO
GEOGRAPHIC ZONE
LOAD(MW)
2,400
2,340
2,280
2,220
2,160
2,100
2,040
1,980
1,920
1,860
1,800
1998 2000 2002 2004 2006 2008 2010 2012 2014 2016 2018 2020 2022 2024 2026 2028 2030 2032
YEAR
Unrestricted Peak
Weather Normalized Peak
2015 Forecast
2016 Forecast


SUMMER PEAK DEMAND FOR EKPC
GEOGRAPHIC ZONE
LOAD(MW)
2,400
2,320
2,240
2,160
2,080
2,000
1,920
1,840
1,760
1,680
1,600
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
YEAR
Unrestricted Peak
Weather Normalized Peak
2015 Forecast
2016 Forecast


WINTER PEAK DEMAND FOR EKPC
GEOGRAPHIC ZONE
LOAD(MW)
3,300
3,150
3,000
2,850
2,700
2,550
2,400
2,250
2,100
1,950
1,800
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
YEAR
Unrestricted Peak
Weather Normalized Peak
2015 Forecast
2016 Forecast

SUMMER PEAK DEMAND FOR DOM GEOGRAPHIC ZONE



WINTER PEAK DEMAND FOR DOM GEOGRAPHIC ZONE

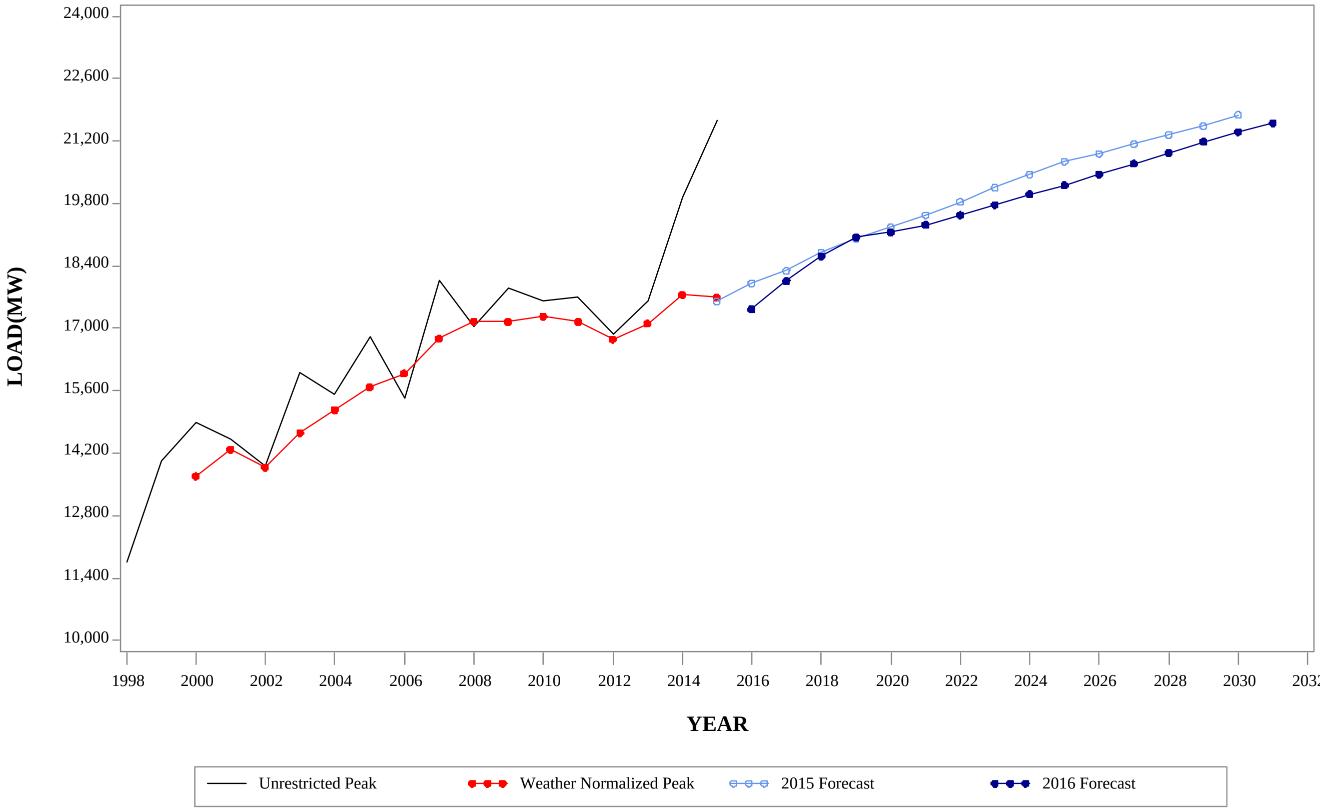


Table A-1

PJM MID-ATLANTIC REGION
SUMMER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST
TO THE JANUARY 2015 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	2016		2021		2026	
	MW	%	MW	%	MW	%
AE	(178)	-6.6%	(266)	-9.6%	(340)	-12.0%
BGE	(267)	-3.7%	(447)	-6.0%	(602)	-7.7%
DPL	(249)	-5.9%	(354)	-8.0%	(461)	-10.0%
JCPL	(394)	-6.2%	(552)	-8.3%	(758)	-11.0%
METED	(67)	-2.2%	(122)	-3.8%	(179)	-5.3%
PECO	(221)	-2.5%	(359)	-3.9%	(381)	-4.0%
PENLC	(88)	-3.0%	(249)	-7.9%	(388)	-11.7%
PEPCO	(131)	-2.0%	(209)	-3.0%	(252)	-3.6%
PL	(69)	-1.0%	(163)	-2.2%	(254)	-3.3%
PS	(328)	-3.1%	(507)	-4.7%	(750)	-6.8%
RECO	(21)	-4.9%	(26)	-6.0%	(33)	-7.4%
UGI	(12)	-6.0%	(18)	-8.7%	(24)	-11.2%
PJM MID-ATLANTIC	(2,537)	-4.2%	(3,748)	-6.0%	(4,683)	-7.3%
FE-EAST	(630)	-5.2%	(1,000)	-7.8%	(1,369)	-10.3%
PLGRP	(96)	-1.3%	(199)	-2.6%	(283)	-3.5%

Table A-1

**PJM WESTERN REGION, PJM SOUTHERN REGION AND PJM RTO
SUMMER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST
TO THE JANUARY 2015 LOAD FORECAST REPORT**

INCREASE OR DECREASE OVER PRIOR FORECAST

	2016		2021		2026	
	MW	%	MW	%	MW	%
AEP	(806)	-3.4%	(728)	-3.0%	(648)	-2.5%
APS	(55)	-0.6%	(73)	-0.8%	(246)	-2.5%
ATSI	(448)	-3.4%	(478)	-3.5%	(501)	-3.6%
COMED	(1,351)	-5.8%	(2,026)	-8.2%	(2,643)	-10.1%
DAYTON	(172)	-4.8%	(261)	-6.9%	(364)	-9.1%
DEOK	(140)	-2.5%	(168)	-2.9%	(215)	-3.5%
DLCO	(112)	-3.7%	(155)	-5.0%	(202)	-6.3%
EKPC	(86)	-4.3%	(114)	-5.4%	(150)	-6.8%
PJM WESTERN	(3,005)	-3.7%	(3,810)	-4.5%	(4,580)	-5.1%
DOM	(1,020)	-5.0%	(1,313)	-5.9%	(1,904)	-8.0%
PJM RTO	(5,781)	-3.7%	(8,406)	-5.1%	(11,007)	-6.4%

Table A-2

PJM MID-ATLANTIC REGION
WINTER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST
TO THE JANUARY 2015 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	15/16		20/21		25/26	
	MW	%	MW	%	MW	%
AE	(64)	-3.8%	(111)	-6.4%	(141)	-8.0%
BGE	96	1.6%	72	1.2%	40	0.6%
DPL	(11)	-0.3%	(21)	-0.6%	(49)	-1.3%
JCPL	(106)	-2.7%	(193)	-4.8%	(304)	-7.2%
METED	(32)	-1.2%	(84)	-3.0%	(150)	-5.1%
PECO	(4)	-0.1%	(144)	-2.1%	(249)	-3.4%
PENLC	(130)	-4.4%	(316)	-10.0%	(480)	-14.5%
PEPCO	19	0.4%	(35)	-0.6%	(117)	-2.0%
PL	(104)	-1.4%	(193)	-2.5%	(308)	-3.9%
PS	62	0.9%	(18)	-0.3%	(135)	-1.9%
RECO	(2)	-0.9%	(2)	-0.8%	(3)	-1.3%
UGI	(10)	-5.0%	(14)	-6.7%	(21)	-9.8%
PJM MID-ATLANTIC	(351)	-0.8%	(1,131)	-2.3%	(1,977)	-4.0%
FE-EAST	(291)	-3.1%	(615)	-6.2%	(934)	-9.0%
PLGRP	(121)	-1.6%	(216)	-2.8%	(335)	-4.2%

Table A-2

**PJM WESTERN REGION, PJM SOUTHERN REGION AND PJM RTO
WINTER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST
TO THE JANUARY 2015 LOAD FORECAST REPORT**

INCREASE OR DECREASE OVER PRIOR FORECAST

	15/16		20/21		25/26	
	MW	%	MW	%	MW	%
AEP	(432)	-1.9%	(75)	-0.3%	155	0.6%
APS	(311)	-3.5%	(161)	-1.7%	(353)	-3.6%
ATSI	(43)	-0.4%	61	0.6%	159	1.5%
COMED	(362)	-2.3%	(633)	-3.7%	(835)	-4.7%
DAYTON	(98)	-3.3%	(128)	-4.1%	(179)	-5.5%
DEOK	29	0.7%	85	1.9%	120	2.6%
DLCO	(43)	-2.0%	(60)	-2.7%	(81)	-3.5%
EKPC	154	6.3%	184	7.3%	203	7.8%
PJM WESTERN	(1,063)	-1.5%	(765)	-1.1%	(882)	-1.2%
DOM	(586)	-3.3%	(224)	-1.1%	(463)	-2.2%
PJM RTO	(1,478)	-1.1%	(1,616)	-1.2%	(2,698)	-1.9%

Table B-1

**SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2016 - 2026**

	METERED 2015	UNRESTRICTED 2015	NORMAL 2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Annual Growth Rate (10 yr)
AE	2,553	2,553	2,580	2,524	2,530	2,534	2,534	2,521	2,507	2,506	2,502	2,503	2,506	2,502	(0.1%)
				-2.2%	0.2%	0.2%	0.0%	-0.5%	-0.6%	-0.0%	-0.2%	0.0%	0.1%	-0.2%	
BGE	6,508	6,508	6,750	6,945	6,989	7,060	7,064	7,079	7,064	7,060	7,078	7,140	7,190	7,220	0.4%
				2.9%	0.6%	1.0%	0.1%	0.2%	-0.2%	-0.1%	0.3%	0.9%	0.7%	0.4%	
DPL	3,822	3,822	3,930	3,991	4,030	4,055	4,068	4,071	4,064	4,071	4,076	4,092	4,121	4,135	0.4%
				1.6%	1.0%	0.6%	0.3%	0.1%	-0.2%	0.2%	0.1%	0.4%	0.7%	0.3%	
JCPL	5,819	5,819	6,010	5,968	6,038	6,096	6,103	6,097	6,091	6,076	6,082	6,100	6,131	6,156	0.3%
				-0.7%	1.2%	1.0%	0.1%	-0.1%	-0.1%	-0.2%	0.1%	0.3%	0.5%	0.4%	
METED	2,791	2,792	2,870	2,940	2,975	3,019	3,051	3,045	3,055	3,068	3,075	3,123	3,147	3,176	0.8%
				2.4%	1.2%	1.5%	1.1%	-0.2%	0.3%	0.4%	0.2%	1.6%	0.8%	0.9%	
PECO	8,095	8,095	8,390	8,547	8,658	8,745	8,797	8,809	8,797	8,842	8,885	8,954	9,012	9,122	0.7%
				1.9%	1.3%	1.0%	0.6%	0.1%	-0.1%	0.5%	0.5%	0.8%	0.6%	1.2%	
PENLC	2,819	2,819	2,940	2,890	2,900	2,904	2,908	2,907	2,899	2,901	2,899	2,903	2,908	2,919	0.1%
				-1.7%	0.3%	0.1%	0.1%	-0.0%	-0.3%	0.1%	-0.1%	0.1%	0.2%	0.4%	
PEPCO	6,268	6,268	6,090	6,563	6,614	6,630	6,669	6,702	6,672	6,680	6,693	6,716	6,750	6,813	0.4%
				7.8%	0.8%	0.2%	0.6%	0.5%	-0.4%	0.1%	0.2%	0.3%	0.5%	0.9%	
PL	6,580	6,580	6,920	7,193	7,270	7,338	7,377	7,362	7,376	7,405	7,424	7,469	7,517	7,560	0.5%
				3.9%	1.1%	0.9%	0.5%	-0.2%	0.2%	0.4%	0.3%	0.6%	0.6%	0.6%	
PS	9,595	9,595	9,910	10,090	10,173	10,234	10,239	10,214	10,191	10,187	10,179	10,186	10,207	10,222	0.1%
				1.8%	0.8%	0.6%	0.0%	-0.2%	-0.2%	-0.0%	-0.1%	0.1%	0.2%	0.1%	
RECO	398	398	405	407	409	411	411	411	409	409	409	409	410	410	0.1%
				0.5%	0.5%	0.5%	0.0%	0.0%	-0.5%	0.0%	0.0%	0.0%	0.2%	0.0%	
UGI	189	189	195	188	190	191	191	190	189	189	189	190	190	190	0.1%
				-3.6%	1.1%	0.5%	0.0%	-0.5%	-0.5%	0.0%	0.0%	0.5%	0.0%	0.0%	
DIVERSITY - MID-ATLANTIC(-)				1,072	1,040	1,023	948	885	1,004	956	876	944	793	872	
PJM MID-ATLANTIC	54,890	54,890	56,495	57,174	57,736	58,194	58,464	58,523	58,310	58,438	58,615	58,841	59,296	59,553	0.4%
				1.2%	1.0%	0.8%	0.5%	0.1%	-0.4%	0.2%	0.3%	0.4%	0.8%	0.4%	
FE-EAST	11,267	11,267	11,670	11,538	11,655	11,762	11,810	11,771	11,765	11,795	11,831	11,882	11,929	11,982	0.4%
				-1.1%	1.0%	0.9%	0.4%	-0.3%	-0.1%	0.3%	0.3%	0.4%	0.4%	0.4%	
PLGRP	6,759	6,759	7,110	7,336	7,417	7,487	7,525	7,513	7,521	7,548	7,576	7,620	7,666	7,714	0.5%
				3.2%	1.1%	0.9%	0.5%	-0.2%	0.1%	0.4%	0.4%	0.6%	0.6%	0.6%	

Notes:
Normal 2015 and all forecast values are non-coincident as estimated by PJM staff.
Normal 2015 and all forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2016).
Summer season indicates peak from June, July, August.

Table B-1 (Continued)

**SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2027 - 2031**

	2027	2028	2029	2030	2031	Annual Growth Rate (15 yr)
AE	2,497	2,493	2,489	2,484	2,485	(0.1%)
	-0.2%	-0.2%	-0.2%	-0.2%	0.0%	
BGE	7,231	7,238	7,299	7,321	7,374	0.4%
	0.2%	0.1%	0.8%	0.3%	0.7%	
DPL	4,140	4,155	4,171	4,181	4,200	0.3%
	0.1%	0.4%	0.4%	0.2%	0.5%	
JCPL	6,181	6,174	6,210	6,218	6,255	0.3%
	0.4%	-0.1%	0.6%	0.1%	0.6%	
METED	3,205	3,213	3,259	3,301	3,332	0.8%
	0.9%	0.2%	1.4%	1.3%	0.9%	
PECO	9,161	9,237	9,320	9,404	9,487	0.7%
	0.4%	0.8%	0.9%	0.9%	0.9%	
PENLC	2,919	2,920	2,924	2,933	2,942	0.1%
	0.0%	0.0%	0.1%	0.3%	0.3%	
PEPCO	6,811	6,833	6,847	6,893	6,935	0.4%
	-0.0%	0.3%	0.2%	0.7%	0.6%	
PL	7,619	7,659	7,714	7,769	7,831	0.6%
	0.8%	0.5%	0.7%	0.7%	0.8%	
PS	10,241	10,243	10,253	10,271	10,297	0.1%
	0.2%	0.0%	0.1%	0.2%	0.3%	
RECO	410	410	411	411	412	0.1%
	0.0%	0.0%	0.2%	0.0%	0.2%	
UGI	191	191	192	193	194	0.2%
	0.5%	0.0%	0.5%	0.5%	0.5%	
DIVERSITY - MID-ATLANTIC(-)	1,002	877	913	961	804	
PJM MID-ATLANTIC	59,604	59,889	60,176	60,418	60,940	0.4%
	0.1%	0.5%	0.5%	0.4%	0.9%	
FE-EAST	12,036	12,095	12,164	12,216	12,290	0.4%
	0.5%	0.5%	0.6%	0.4%	0.6%	
PLGRP	7,770	7,816	7,876	7,924	7,986	0.6%
	0.7%	0.6%	0.8%	0.6%	0.8%	

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2016).
Summer season indicates peak from June, July, August.

Table B-1

**SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2016 - 2026**

	METERED 2015	UNRESTRICTED 2015	NORMAL 2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Annual Growth Rate (10 yr)
AEP	21,877	21,877	22,490	23,006	23,309	23,584	23,799	23,819	23,943	24,119	24,280	24,517	24,690	24,891	0.8%
				2.3%	1.3%	1.2%	0.9%	0.1%	0.5%	0.7%	0.7%	1.0%	0.7%	0.8%	
APS	8,257	8,257	8,480	8,817	9,014	9,127	9,215	9,248	9,266	9,314	9,350	9,413	9,497	9,554	0.8%
				4.0%	2.2%	1.3%	1.0%	0.4%	0.2%	0.5%	0.4%	0.7%	0.9%	0.6%	
ATSI	12,357	12,357	12,870	12,921	13,004	13,089	13,149	13,129	13,158	13,207	13,236	13,313	13,361	13,413	0.4%
				0.4%	0.6%	0.7%	0.5%	-0.2%	0.2%	0.4%	0.2%	0.6%	0.4%	0.4%	
COMED	19,766	19,768	21,950	22,001	22,216	22,438	22,633	22,659	22,767	22,935	23,045	23,248	23,449	23,633	0.7%
				0.2%	1.0%	1.0%	0.9%	0.1%	0.5%	0.7%	0.5%	0.9%	0.9%	0.8%	
DAYTON	3,269	3,269	3,300	3,403	3,453	3,496	3,524	3,512	3,526	3,548	3,568	3,599	3,622	3,647	0.7%
				3.1%	1.5%	1.2%	0.8%	-0.3%	0.4%	0.6%	0.6%	0.9%	0.6%	0.7%	
DEOK	5,123	5,123	5,180	5,436	5,500	5,566	5,616	5,621	5,648	5,685	5,714	5,771	5,824	5,853	0.7%
				4.9%	1.2%	1.2%	0.9%	0.1%	0.5%	0.7%	0.5%	1.0%	0.9%	0.5%	
DLCO	2,805	2,805	2,870	2,893	2,918	2,938	2,950	2,942	2,942	2,948	2,951	2,963	2,973	2,985	0.3%
				0.8%	0.9%	0.7%	0.4%	-0.3%	0.0%	0.2%	0.1%	0.4%	0.3%	0.4%	
EKPC	1,920	1,920	1,920	1,924	1,947	1,960	1,974	1,977	1,985	1,989	2,006	2,021	2,031	2,041	0.6%
				0.2%	1.2%	0.7%	0.7%	0.2%	0.4%	0.2%	0.9%	0.7%	0.5%	0.5%	
DIVERSITY - WESTERN(-)				1,572	1,589	1,564	1,558	1,559	1,580	1,614	1,493	1,547	1,574	1,574	
PJM WESTERN	74,531	74,579	77,980	78,829	79,772	80,634	81,302	81,348	81,655	82,131	82,657	83,298	83,873	84,443	0.7%
				1.1%	1.2%	1.1%	0.8%	0.1%	0.4%	0.6%	0.6%	0.8%	0.7%	0.7%	
DOM	18,980	19,024	18,920	19,531	20,052	20,499	20,813	20,882	21,054	21,244	21,421	21,640	21,854	22,041	1.2%
				3.2%	2.7%	2.2%	1.5%	0.3%	0.8%	0.9%	0.8%	1.0%	1.0%	0.9%	
DIVERSITY - INTERREGIONAL(-)				3,403	3,411	3,414	3,621	3,866	3,661	3,827	3,718	3,788	4,076	4,146	
PJM RTO	143,447	143,497	150,295	152,131	154,149	155,913	156,958	156,887	157,358	157,986	158,975	159,991	160,947	161,891	0.6%
				1.2%	1.3%	1.1%	0.7%	-0.0%	0.3%	0.4%	0.6%	0.6%	0.6%	0.6%	

Notes:
Normal 2015 and all forecast values are non-coincident as estimated by PJM staff.
Normal 2015 and all forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2016).
Summer season indicates peak from June, July, August.

Table B-1 (Continued)

SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO 2027 - 2031

	2027	2028	2029	2030	2031	Annual Growth Rate (15 yr)
AEP	25,113	25,322	25,560	25,828	26,042	0.8%
	0.9%	0.8%	0.9%	1.0%	0.8%	
APS	9,612	9,665	9,734	9,814	9,902	0.8%
	0.6%	0.6%	0.7%	0.8%	0.9%	
ATSI	13,487	13,544	13,618	13,713	13,779	0.4%
	0.6%	0.4%	0.5%	0.7%	0.5%	
COMED	23,840	24,016	24,174	24,460	24,695	0.8%
	0.9%	0.7%	0.7%	1.2%	1.0%	
DAYTON	3,675	3,706	3,738	3,772	3,799	0.7%
	0.8%	0.8%	0.9%	0.9%	0.7%	
DEOK	5,901	5,942	6,003	6,063	6,119	0.8%
	0.8%	0.7%	1.0%	1.0%	0.9%	
DLCO	3,000	3,012	3,026	3,042	3,057	0.4%
	0.5%	0.4%	0.5%	0.5%	0.5%	
EKPC	2,052	2,063	2,075	2,093	2,104	0.6%
	0.5%	0.5%	0.6%	0.9%	0.5%	
DIVERSITY - WESTERN(-)	1,581	1,478	1,415	1,562	1,590	
PJM WESTERN	85,099	85,792	86,513	87,223	87,907	0.7%
	0.8%	0.8%	0.8%	0.8%	0.8%	
DOM	22,256	22,466	22,695	22,904	23,085	1.1%
	1.0%	0.9%	1.0%	0.9%	0.8%	
DIVERSITY - INTERREGIONAL(-)	3,971	4,002	3,992	4,133	4,463	
PJM RTO	162,988	164,145	165,392	166,412	167,469	0.6%
	0.7%	0.7%	0.8%	0.6%	0.6%	

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2016).
Summer season indicates peak from June, July, August.

Table B-2

WINTER PEAK LOAD (MW) AND GROWTH RATES FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2015/16 - 2025/26

	METERED 14/15	UNRESTRICTED 14/15	NORMAL 14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	Annual Growth Rate (10 yr)
AE	1,705	1,705	1,610	1,626	1,632	1,640	1,647	1,634	1,620	1,620	1,621	1,623	1,623	1,624	(0.0%)
				1.0%	0.4%	0.5%	0.4%	-0.8%	-0.9%	0.0%	0.1%	0.1%	0.0%	0.1%	
BGE	6,712	6,712	5,760	5,941	5,994	6,044	6,078	6,080	6,077	6,098	6,118	6,142	6,168	6,199	0.4%
				3.1%	0.9%	0.8%	0.6%	0.0%	-0.0%	0.3%	0.3%	0.4%	0.4%	0.5%	
DPL	4,114	4,114	3,480	3,413	3,461	3,507	3,538	3,545	3,548	3,560	3,577	3,598	3,623	3,646	0.7%
				-1.9%	1.4%	1.3%	0.9%	0.2%	0.1%	0.3%	0.5%	0.6%	0.7%	0.6%	
JCPL	3,805	3,805	3,730	3,766	3,822	3,880	3,914	3,881	3,853	3,857	3,859	3,874	3,885	3,892	0.3%
				1.0%	1.5%	1.5%	0.9%	-0.8%	-0.7%	0.1%	0.1%	0.4%	0.3%	0.2%	
METED	2,799	2,799	2,610	2,593	2,637	2,679	2,711	2,704	2,700	2,711	2,730	2,748	2,767	2,784	0.7%
				-0.7%	1.7%	1.6%	1.2%	-0.3%	-0.1%	0.4%	0.7%	0.7%	0.7%	0.6%	
PECO	7,034	7,034	6,620	6,654	6,770	6,858	6,909	6,891	6,862	6,899	6,929	6,964	6,996	7,030	0.6%
				0.5%	1.7%	1.3%	0.7%	-0.3%	-0.4%	0.5%	0.4%	0.5%	0.5%	0.5%	
PENLC	3,025	3,025	2,860	2,814	2,828	2,836	2,849	2,841	2,829	2,830	2,833	2,835	2,834	2,834	0.1%
				-1.6%	0.5%	0.3%	0.5%	-0.3%	-0.4%	0.0%	0.1%	0.1%	-0.0%	0.0%	
PEPCO	6,066	6,066	5,370	5,386	5,455	5,514	5,555	5,572	5,564	5,593	5,617	5,643	5,668	5,684	0.5%
				0.3%	1.3%	1.1%	0.7%	0.3%	-0.1%	0.5%	0.4%	0.5%	0.4%	0.3%	
PL	7,845	7,845	7,140	7,210	7,297	7,385	7,437	7,427	7,404	7,417	7,438	7,475	7,511	7,541	0.4%
				1.0%	1.2%	1.2%	0.7%	-0.1%	-0.3%	0.2%	0.3%	0.5%	0.5%	0.4%	
PS	6,697	6,697	6,570	6,712	6,801	6,868	6,923	6,890	6,847	6,842	6,856	6,871	6,886	6,904	0.3%
				2.2%	1.3%	1.0%	0.8%	-0.5%	-0.6%	-0.1%	0.2%	0.2%	0.2%	0.3%	
RECO	232	232	220	232	234	235	237	235	234	235	235	235	234	234	0.1%
				5.5%	0.9%	0.4%	0.9%	-0.8%	-0.4%	0.4%	0.0%	0.0%	-0.4%	0.0%	
UGI	211	211	200	192	194	196	197	195	194	193	193	193	193	193	0.1%
				-4.0%	1.0%	1.0%	0.5%	-1.0%	-0.5%	-0.5%	0.0%	0.0%	0.0%	0.0%	
DIVERSITY - MID-ATLANTIC(-)				717	621	632	738	798	733	670	659	644	761	745	
PJM MID-ATLANTIC	49,369	49,369	45,485	45,822	46,504	47,010	47,257	47,097	46,999	47,185	47,347	47,557	47,627	47,820	0.4%
				0.7%	1.5%	1.1%	0.5%	-0.3%	-0.2%	0.4%	0.3%	0.4%	0.1%	0.4%	
FE-EAST	9,505	9,505	9,140	9,095	9,229	9,335	9,406	9,336	9,305	9,323	9,358	9,403	9,411	9,442	0.4%
				-0.5%	1.5%	1.1%	0.8%	-0.7%	-0.3%	0.2%	0.4%	0.5%	0.1%	0.3%	
PLGRP	8,055	8,055	7,335	7,387	7,476	7,566	7,610	7,584	7,578	7,595	7,614	7,653	7,680	7,711	0.4%
				0.7%	1.2%	1.2%	0.6%	-0.3%	-0.1%	0.2%	0.3%	0.5%	0.4%	0.4%	

Notes:
Normal 14/15 and all forecast values are non-coincident as estimated by PJM staff.
Normal 14/15 and all forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2015/16).
Winter season indicates peak from December, January, February.

Table B-2 (Continued)

WINTER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION 2026/27 - 2030/31

	26/27	27/28	28/29	29/30	30/31	Annual Growth Rate (15 yr)
AE	1,627	1,636	1,639	1,648	1,644	0.1%
	0.2%	0.6%	0.2%	0.5%	-0.2%	
BGE	6,226	6,261	6,292	6,317	6,345	0.4%
	0.4%	0.6%	0.5%	0.4%	0.4%	
DPL	3,669	3,694	3,718	3,742	3,766	0.7%
	0.6%	0.7%	0.6%	0.6%	0.6%	
JCPL	3,913	3,945	3,967	3,995	4,006	0.4%
	0.5%	0.8%	0.6%	0.7%	0.3%	
METED	2,807	2,830	2,855	2,879	2,898	0.7%
	0.8%	0.8%	0.9%	0.8%	0.7%	
PECO	7,076	7,130	7,180	7,221	7,262	0.6%
	0.7%	0.8%	0.7%	0.6%	0.6%	
PENLC	2,836	2,842	2,841	2,852	2,847	0.1%
	0.1%	0.2%	-0.0%	0.4%	-0.2%	
PEPCO	5,711	5,768	5,781	5,836	5,868	0.6%
	0.5%	1.0%	0.2%	1.0%	0.5%	
PL	7,582	7,625	7,666	7,702	7,745	0.5%
	0.5%	0.6%	0.5%	0.5%	0.6%	
PS	6,921	6,955	6,981	7,028	7,035	0.3%
	0.2%	0.5%	0.4%	0.7%	0.1%	
RECO	235	237	236	238	236	0.1%
	0.4%	0.9%	-0.4%	0.8%	-0.8%	
UGI	193	194	194	195	194	0.1%
	0.0%	0.5%	0.0%	0.5%	-0.5%	
DIVERSITY - MID-ATLANTIC(-)	722	718	669	699	749	
PJM MID-ATLANTIC	48,074	48,399	48,681	48,954	49,097	0.5%
	0.5%	0.7%	0.6%	0.6%	0.3%	
FE-EAST	9,485	9,544	9,603	9,669	9,684	0.4%
	0.5%	0.6%	0.6%	0.7%	0.2%	
PLGRP	7,752	7,796	7,840	7,873	7,919	0.5%
	0.5%	0.6%	0.6%	0.4%	0.6%	

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2015/16).
Winter season indicates peak from December, January, February.

Table B-2

WINTER PEAK LOAD (MW) AND GROWTH RATES FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2015/16 - 2025/26

	METERED 14/15	UNRESTRICTED 14/15	NORMAL 14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	Annual Growth Rate (10 yr)
AEP	24,739	24,739	21,990	22,506	22,889	23,295	23,615	23,697	23,764	23,948	24,127	24,356	24,565	24,783	1.0%
				2.3%	1.7%	1.8%	1.4%	0.3%	0.3%	0.8%	0.7%	0.9%	0.9%	0.9%	
APS	9,594	9,594	8,640	8,526	8,778	9,009	9,149	9,200	9,201	9,256	9,306	9,373	9,442	9,494	1.1%
				-1.3%	3.0%	2.6%	1.6%	0.6%	0.0%	0.6%	0.5%	0.7%	0.7%	0.6%	
ATSI	11,041	11,041	10,630	10,549	10,657	10,747	10,851	10,823	10,806	10,848	10,906	10,949	10,995	11,038	0.5%
				-0.8%	1.0%	0.8%	1.0%	-0.3%	-0.2%	0.4%	0.5%	0.4%	0.4%	0.4%	
COMED	15,951	15,951	15,120	15,579	15,832	16,051	16,296	16,325	16,297	16,403	16,532	16,669	16,788	16,974	0.9%
				3.0%	1.6%	1.4%	1.5%	0.2%	-0.2%	0.7%	0.8%	0.8%	0.7%	1.1%	
DAYTON	2,999	2,999	2,960	2,848	2,901	2,955	2,987	2,979	2,980	2,997	3,021	3,044	3,062	3,083	0.8%
				-3.8%	1.9%	1.9%	1.1%	-0.3%	0.0%	0.6%	0.8%	0.8%	0.6%	0.7%	
DEOK	4,750	4,750	4,500	4,422	4,489	4,549	4,597	4,609	4,620	4,658	4,688	4,723	4,754	4,792	0.8%
				-1.7%	1.5%	1.3%	1.1%	0.3%	0.2%	0.8%	0.6%	0.7%	0.7%	0.8%	
DLCO	2,315	2,315	2,180	2,158	2,180	2,195	2,210	2,204	2,198	2,201	2,207	2,210	2,216	2,223	0.3%
				-1.0%	1.0%	0.7%	0.7%	-0.3%	-0.3%	0.1%	0.3%	0.1%	0.3%	0.3%	
EKPC	3,123	3,123	2,370	2,602	2,634	2,665	2,694	2,702	2,714	2,732	2,752	2,769	2,786	2,809	0.8%
				9.8%	1.2%	1.2%	1.1%	0.3%	0.4%	0.7%	0.7%	0.6%	0.6%	0.8%	
DIVERSITY - WESTERN(-)				1,373	1,370	1,417	1,658	1,784	1,602	1,497	1,565	1,553	1,551	1,676	
PJM WESTERN	71,834	71,834	66,940	67,817	68,990	70,049	70,741	70,755	70,978	71,546	71,974	72,540	73,057	73,520	0.8%
				1.3%	1.7%	1.5%	1.0%	0.0%	0.3%	0.8%	0.6%	0.8%	0.7%	0.6%	
DOM	21,651	21,651	17,690	17,431	18,063	18,622	19,048	19,165	19,322	19,547	19,774	20,011	20,212	20,460	1.6%
				-1.5%	3.6%	3.1%	2.3%	0.6%	0.8%	1.2%	1.2%	1.2%	1.0%	1.2%	
DIVERSITY - INTERREGIONAL(-)				827	1,075	1,036	967	995	897	1,015	1,085	918	934	888	
PJM RTO	142,762	142,762	128,270	130,243	132,482	134,645	136,079	136,022	136,402	137,263	138,010	139,190	139,962	140,912	0.8%
				1.5%	1.7%	1.6%	1.1%	-0.0%	0.3%	0.6%	0.5%	0.9%	0.6%	0.7%	

Notes:
Normal 14/15 and all forecast values are non-coincident as estimated by PJM staff.
Normal 14/15 and all forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2015/16).
Winter season indicates peak from December, January, February.

Table B-2 (Continued)

**WINTER PEAK LOAD (MW) AND GROWTH RATES FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2026/27 - 2030/31**

	26/27	27/28	28/29	29/30	30/31	Annual Growth Rate (15 yr)
AEP	25,013	25,283	25,526	25,825	25,993	1.0%
	0.9%	1.1%	1.0%	1.2%	0.7%	
APS	9,557	9,642	9,680	9,783	9,839	1.0%
	0.7%	0.9%	0.4%	1.1%	0.6%	
ATSI	11,082	11,157	11,176	11,298	11,301	0.5%
	0.4%	0.7%	0.2%	1.1%	0.0%	
COMED	17,101	17,291	17,446	17,660	17,698	0.9%
	0.7%	1.1%	0.9%	1.2%	0.2%	
DAYTON	3,108	3,136	3,160	3,185	3,201	0.8%
	0.8%	0.9%	0.8%	0.8%	0.5%	
DEOK	4,832	4,888	4,919	4,957	4,992	0.8%
	0.8%	1.2%	0.6%	0.8%	0.7%	
DLCO	2,231	2,244	2,243	2,259	2,265	0.3%
	0.4%	0.6%	-0.0%	0.7%	0.3%	
EKPC	2,831	2,853	2,869	2,899	2,912	0.8%
	0.8%	0.8%	0.6%	1.0%	0.4%	
DIVERSITY - WESTERN(-)	1,622	1,667	1,614	1,828	1,678	
PJM WESTERN	74,133	74,827	75,405	76,038	76,523	0.8%
	0.8%	0.9%	0.8%	0.8%	0.6%	
DOM	20,698	20,943	21,188	21,411	21,608	1.4%
	1.2%	1.2%	1.2%	1.1%	0.9%	
DIVERSITY - INTERREGIONAL(-)	918	1,020	1,357	1,100	1,003	
PJM RTO	141,987	143,149	143,917	145,303	146,225	0.8%
	0.8%	0.8%	0.5%	1.0%	0.6%	

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2015/16).
Winter season indicates peak from December, January, February.

Table B-3

SPRING PEAK LOAD (MW) FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2016 - 2031

	2016	2017	2018	2019	2020	2021	2022	2023
AE	1,699	1,711	1,717	1,720	1,694	1,690	1,691	1,694
BGE	5,523	5,565	5,606	5,628	5,590	5,608	5,648	5,664
DPL	3,018	3,068	3,098	3,110	3,105	3,114	3,117	3,132
JCPL	4,142	4,258	4,325	4,361	4,252	4,228	4,273	4,310
METED	2,430	2,476	2,512	2,521	2,504	2,514	2,548	2,570
PECO	6,667	6,779	6,870	6,937	6,828	6,842	6,956	7,003
PENLC	2,576	2,594	2,598	2,598	2,586	2,585	2,581	2,583
PEPCO	5,254	5,328	5,389	5,425	5,357	5,365	5,399	5,444
PL	6,377	6,481	6,547	6,581	6,549	6,578	6,596	6,629
PS	7,635	7,777	7,852	7,879	7,747	7,738	7,786	7,822
RECO	296	298	300	301	299	299	299	299
UGI	167	170	171	171	169	169	169	169
DIVERSITY - MID-ATLANTIC(-)	2,366	2,200	2,199	2,329	2,747	3,047	2,486	2,201
PJM MID-ATLANTIC	43,418	44,305	44,786	44,903	43,933	43,683	44,577	45,118
FE-EAST	8,691	8,861	8,963	8,977	8,793	8,787	8,915	9,012
PLGRP	6,423	6,499	6,578	6,609	6,574	6,581	6,621	6,643

	2024	2025	2026	2027	2028	2029	2030	2031
AE	1,696	1,687	1,686	1,685	1,688	1,685	1,677	1,666
BGE	5,689	5,697	5,734	5,765	5,783	5,816	5,826	5,843
DPL	3,145	3,158	3,182	3,199	3,209	3,225	3,228	3,229
JCPL	4,347	4,328	4,310	4,322	4,387	4,418	4,428	4,434
METED	2,577	2,595	2,615	2,641	2,678	2,703	2,719	2,736
PECO	7,063	7,040	7,086	7,148	7,288	7,362	7,413	7,407
PENLC	2,568	2,563	2,577	2,581	2,581	2,578	2,574	2,574
PEPCO	5,493	5,477	5,490	5,516	5,583	5,641	5,663	5,648
PL	6,618	6,638	6,712	6,769	6,798	6,820	6,856	6,890
PS	7,840	7,830	7,801	7,818	7,890	7,919	7,925	7,919
RECO	300	299	299	300	300	301	300	300
UGI	168	168	169	169	170	170	169	169
DIVERSITY - MID-ATLANTIC(-)	2,239	2,359	2,816	3,073	2,135	2,131	2,179	2,339
PJM MID-ATLANTIC	45,265	45,121	44,845	44,840	46,220	46,507	46,599	46,476
FE-EAST	9,023	9,024	8,958	9,020	9,225	9,286	9,292	9,318
PLGRP	6,656	6,675	6,710	6,765	6,806	6,857	6,886	6,923

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.
Spring season indicates peak from March, April, May.

Table B-3

SPRING PEAK LOAD (MW) FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2016 - 2031

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
AEP	20,452	20,806	21,200	21,421	21,406	21,701	21,782	21,924	22,077	22,259	22,578	22,798	22,936	23,126	23,321	23,491
APS	7,765	8,012	8,151	8,251	8,242	8,323	8,344	8,419	8,437	8,503	8,604	8,673	8,719	8,757	8,814	8,863
ATSI	10,409	10,499	10,597	10,702	10,459	10,485	10,700	10,745	10,858	10,717	10,761	10,791	11,031	11,119	11,214	11,076
COMED	16,703	16,948	17,183	17,380	17,255	17,329	17,578	17,722	17,916	18,023	18,214	18,319	18,591	18,801	18,961	19,093
DAYTON	2,750	2,797	2,844	2,877	2,844	2,855	2,896	2,919	2,945	2,960	2,979	3,003	3,051	3,083	3,102	3,120
DEOK	4,433	4,487	4,562	4,616	4,553	4,574	4,654	4,683	4,754	4,757	4,771	4,812	4,895	4,963	5,002	5,016
DLCO	2,340	2,359	2,381	2,396	2,381	2,384	2,391	2,397	2,410	2,412	2,424	2,436	2,453	2,467	2,477	2,480
EKPC	2,057	2,090	2,112	2,126	2,132	2,166	2,171	2,189	2,190	2,208	2,241	2,258	2,262	2,271	2,287	2,303
DIVERSITY - WESTERN(-)	4,303	4,393	4,452	4,656	4,899	5,168	4,738	4,765	4,854	5,137	5,419	5,374	5,130	5,086	5,258	5,231
PJM WESTERN	62,606	63,605	64,578	65,113	64,373	64,649	65,778	66,233	66,733	66,702	67,153	67,716	68,808	69,501	69,920	70,211
DOM	17,013	17,508	18,223	18,589	18,621	18,735	18,810	18,954	19,385	19,510	19,716	19,897	19,959	20,286	20,470	20,610
DIVERSITY - INTERREGIONAL(-)	3,519	3,973	4,015	4,599	4,581	4,467	3,859	4,189	4,481	4,479	4,701	4,541	4,343	4,411	4,549	4,556
PJM RTO	119,518	121,445	123,572	124,006	122,346	122,600	125,306	126,116	126,902	126,854	127,013	127,912	130,644	131,883	132,440	132,741

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.
Spring season indicates peak from March, April, May.

Table B-4

FALL PEAK LOAD (MW) FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2016 - 2031

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
AE	1,946	1,956	1,960	1,966	1,952	1,949	1,939	1,940	1,947	1,951	1,952	1,954	1,952	1,955	1,958	1,964
BGE	5,848	5,870	5,892	5,958	5,948	5,961	5,963	5,973	6,026	6,060	6,086	6,115	6,123	6,155	6,202	6,236
DPL	3,263	3,310	3,342	3,373	3,360	3,365	3,361	3,382	3,418	3,436	3,451	3,464	3,479	3,511	3,535	3,547
JCPL	4,541	4,607	4,650	4,683	4,653	4,647	4,637	4,652	4,682	4,708	4,728	4,746	4,758	4,794	4,822	4,858
METED	2,490	2,526	2,557	2,593	2,590	2,600	2,605	2,618	2,653	2,688	2,709	2,732	2,740	2,774	2,813	2,849
PECO	7,151	7,249	7,321	7,416	7,387	7,413	7,426	7,464	7,551	7,605	7,659	7,718	7,762	7,844	7,930	7,996
PENLC	2,581	2,587	2,585	2,594	2,584	2,585	2,586	2,584	2,586	2,593	2,594	2,599	2,599	2,599	2,602	2,618
PEPCO	5,583	5,618	5,636	5,691	5,712	5,725	5,718	5,718	5,753	5,807	5,838	5,869	5,863	5,883	5,936	5,989
PL	6,194	6,290	6,347	6,388	6,346	6,362	6,376	6,421	6,460	6,492	6,532	6,564	6,620	6,669	6,712	6,757
PS	8,138	8,215	8,252	8,320	8,304	8,298	8,263	8,251	8,298	8,352	8,373	8,392	8,359	8,383	8,449	8,509
RECO	316	317	318	321	320	320	319	318	320	321	322	322	321	321	323	325
UGI	162	164	164	165	162	162	162	162	162	162	163	163	163	164	164	165
DIVERSITY - MID-ATLANTIC(-)	938	1,087	998	1,072	771	900	942	1,033	1,037	845	846	851	1,003	1,033	1,028	835
PJM MID-ATLANTIC	47,275	47,622	48,026	48,396	48,547	48,487	48,413	48,450	48,819	49,330	49,561	49,787	49,736	50,019	50,418	50,978
FE-EAST	9,361	9,443	9,511	9,596	9,628	9,607	9,582	9,588	9,660	9,762	9,825	9,868	9,845	9,886	9,983	10,115
PLGRP	6,339	6,426	6,489	6,517	6,496	6,498	6,524	6,556	6,584	6,621	6,670	6,695	6,760	6,797	6,843	6,891

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.
Fall season indicates peak from September, October, November.

Table B-4

FALL PEAK LOAD (MW) FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2016 - 2031

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
AEP	20,550	20,867	21,090	21,294	21,310	21,460	21,583	21,780	21,964	22,162	22,381	22,607	22,773	22,981	23,196	23,463
APS	7,717	7,921	8,030	8,135	8,136	8,178	8,208	8,262	8,333	8,396	8,449	8,515	8,563	8,640	8,711	8,774
ATSI	11,069	11,067	11,100	11,279	11,285	11,333	11,352	11,292	11,442	11,529	11,591	11,648	11,581	11,646	11,817	11,916
COMED	18,021	18,269	18,353	18,635	18,686	18,804	18,898	19,024	19,209	19,445	19,612	19,787	19,922	20,043	20,318	20,558
DAYTON	2,922	2,949	2,969	3,019	3,043	3,059	3,055	3,059	3,089	3,152	3,179	3,201	3,189	3,203	3,249	3,315
DEOK	4,760	4,803	4,813	4,898	4,929	4,957	4,976	4,998	5,034	5,101	5,151	5,185	5,214	5,217	5,295	5,370
DLCO	2,478	2,491	2,496	2,530	2,536	2,540	2,528	2,523	2,545	2,572	2,582	2,594	2,579	2,584	2,618	2,646
EKPC	1,940	1,964	1,973	1,978	1,984	2,002	2,020	2,039	2,035	2,043	2,066	2,078	2,106	2,120	2,120	2,127
DIVERSITY - WESTERN(-)	1,513	1,943	2,134	2,124	1,554	1,720	1,659	1,955	2,146	1,796	1,787	1,869	2,000	2,386	2,228	1,977
PJM WESTERN	67,944	68,388	68,690	69,644	70,355	70,613	70,961	71,022	71,505	72,604	73,224	73,746	73,927	74,048	75,096	76,192
DOM	17,296	17,925	18,459	18,774	18,754	18,852	18,954	19,266	19,548	19,731	19,901	20,006	20,252	20,509	20,688	20,847
DIVERSITY - INTERREGIONAL(-)	4,091	4,174	4,575	4,462	4,328	4,288	4,015	4,197	4,433	4,331	4,350	4,184	4,229	4,443	4,448	4,181
PJM RTO	128,424	129,761	130,600	132,352	133,328	133,664	134,313	134,541	135,439	137,334	138,336	139,355	139,686	140,133	141,754	143,836

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.
Fall season indicates peak from September, October, November.

Table B-5

MONTHLY PEAK FORECAST (MW) FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	MID-ATLANTIC DIVERSITY	PJM MID-ATLANTIC
Jan 2016	1,626	5,941	3,413	3,766	2,593	6,654	2,814	5,386	7,210	6,712	227	192	712	45,822
Feb 2016	1,561	5,615	3,262	3,674	2,493	6,365	2,778	5,156	6,819	6,499	219	182	946	43,677
Mar 2016	1,379	5,045	2,918	3,206	2,369	5,874	2,576	4,574	6,377	5,983	206	167	1,502	39,172
Apr 2016	1,337	4,720	2,689	3,323	2,221	5,828	2,400	4,274	5,860	6,452	220	147	2,595	36,876
May 2016	1,699	5,523	3,018	4,142	2,430	6,667	2,466	5,254	5,934	7,635	296	147	1,793	43,418
Jun 2016	2,238	6,564	3,715	5,439	2,801	8,132	2,780	6,279	6,801	9,508	379	174	670	54,140
Jul 2016	2,524	6,945	3,991	5,968	2,940	8,547	2,890	6,563	7,193	10,090	407	188	1,072	57,174
Aug 2016	2,416	6,724	3,830	5,424	2,834	8,116	2,766	6,372	6,863	9,365	367	173	723	54,527
Sep 2016	1,946	5,848	3,263	4,541	2,490	7,151	2,581	5,583	6,194	8,138	316	157	933	47,275
Oct 2016	1,417	4,645	2,633	3,403	2,139	5,772	2,375	4,298	5,695	6,373	241	144	1,520	37,615
Nov 2016	1,387	4,742	2,695	3,240	2,250	5,787	2,505	4,340	6,146	6,039	213	162	481	39,025
Dec 2016	1,613	5,522	3,171	3,820	2,518	6,499	2,806	5,207	6,815	6,752	238	187	576	44,572
	AE	**BGE**	**DPL**	**JCPL**	**METED**	**PECO**	**PENLC**	**PEPCO**	**PL**	**PS**	**RECO**	**UGI**	**DIVERSITY**	**MID-ATLANTIC**
Jan 2017	1,632	5,994	3,461	3,822	2,637	6,770	2,828	5,455	7,297	6,801	228	194	615	46,504
Feb 2017	1,569	5,658	3,317	3,717	2,533	6,490	2,793	5,211	6,916	6,589	220	184	772	44,425
Mar 2017	1,388	5,095	2,956	3,258	2,418	5,968	2,594	4,600	6,481	6,072	208	170	1,446	39,762
Apr 2017	1,336	4,756	2,707	3,293	2,261	5,839	2,423	4,327	5,912	6,252	228	149	2,354	37,129
May 2017	1,711	5,565	3,068	4,258	2,476	6,779	2,480	5,328	6,021	7,777	298	149	1,605	44,305
Jun 2017	2,244	6,601	3,762	5,516	2,849	8,259	2,807	6,326	6,878	9,582	382	176	690	54,692
Jul 2017	2,530	6,989	4,030	6,038	2,975	8,658	2,900	6,614	7,270	10,173	409	190	1,040	57,736
Aug 2017	2,417	6,753	3,860	5,485	2,878	8,216	2,785	6,420	6,905	9,417	369	174	665	55,014
Sep 2017	1,956	5,870	3,310	4,607	2,526	7,249	2,587	5,618	6,290	8,215	317	158	1,081	47,622
Oct 2017	1,430	4,742	2,720	3,543	2,205	6,027	2,391	4,375	5,830	6,678	247	146	1,501	38,833
Nov 2017	1,401	4,797	2,742	3,293	2,293	5,884	2,520	4,389	6,242	6,104	215	164	548	39,496
Dec 2017	1,617	5,551	3,213	3,870	2,559	6,584	2,800	5,257	6,884	6,797	235	189	533	45,023
	AE	**BGE**	**DPL**	**JCPL**	**METED**	**PECO**	**PENLC**	**PEPCO**	**PL**	**PS**	**RECO**	**UGI**	**DIVERSITY**	**MID-ATLANTIC**
Jan 2018	1,640	6,044	3,507	3,880	2,679	6,858	2,836	5,514	7,385	6,868	229	196	626	47,010
Feb 2018	1,579	5,709	3,365	3,786	2,582	6,573	2,800	5,272	6,999	6,656	221	186	719	45,009
Mar 2018	1,387	5,120	2,981	3,290	2,452	5,996	2,598	4,639	6,547	6,095	208	171	1,569	39,915
Apr 2018	1,343	4,819	2,786	3,518	2,298	6,068	2,422	4,360	6,020	6,696	235	150	2,880	37,835
May 2018	1,717	5,606	3,098	4,325	2,512	6,870	2,491	5,389	6,093	7,852	300	151	1,618	44,786
Jun 2018	2,251	6,653	3,776	5,565	2,881	8,342	2,807	6,343	6,932	9,594	380	177	757	54,944
Jul 2018	2,534	7,060	4,055	6,096	3,019	8,745	2,904	6,630	7,338	10,234	411	191	1,023	58,194
Aug 2018	2,424	6,827	3,892	5,535	2,906	8,294	2,787	6,445	6,974	9,435	369	175	697	55,366
Sep 2018	1,960	5,892	3,342	4,650	2,557	7,321	2,585	5,636	6,347	8,252	318	159	993	48,026
Oct 2018	1,442	4,785	2,838	3,671	2,243	6,178	2,407	4,425	5,983	6,853	250	147	1,904	39,318
Nov 2018	1,402	4,827	2,780	3,321	2,315	5,951	2,533	4,413	6,283	6,130	215	164	529	39,805
Dec 2018	1,633	5,607	3,259	3,914	2,607	6,668	2,826	5,326	6,982	6,882	237	191	746	45,386

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.

Table B-5

MONTHLY PEAK FORECAST (MW) FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	WESTERN DIVERSITY	PJM WESTERN	DOM	INTER REGION DIVERSITY	PJM RTO
Jan 2016	22,506	8,526	10,549	15,433	2,848	4,422	2,158	2,602	1,227	67,817	17,431	827	130,243
Feb 2016	21,476	8,157	10,427	15,180	2,745	4,247	2,090	2,365	1,445	65,242	16,087	649	124,357
Mar 2016	20,452	7,765	9,698	13,803	2,548	3,905	1,989	2,057	1,818	60,399	15,912	809	114,674
Apr 2016	18,966	7,102	9,169	13,636	2,452	3,840	2,072	1,690	2,250	56,677	15,692	1,041	108,204
May 2016	19,557	7,383	10,409	16,703	2,750	4,433	2,340	1,564	2,533	62,606	17,013	3,519	119,518
Jun 2016	22,148	8,467	12,466	20,493	3,184	5,176	2,796	1,841	1,137	75,434	18,687	4,188	144,073
Jul 2016	23,006	8,817	12,921	22,001	3,403	5,436	2,893	1,924	1,572	78,829	19,531	3,403	152,131
Aug 2016	22,778	8,642	12,587	21,325	3,337	5,386	2,828	1,918	989	77,812	19,226	3,661	147,904
Sep 2016	20,550	7,717	11,069	18,021	2,922	4,760	2,478	1,716	1,289	67,944	17,296	4,091	128,424
Oct 2016	18,302	6,861	8,981	13,755	2,398	3,876	1,994	1,655	2,100	55,722	15,102	2,474	105,965
Nov 2016	19,315	7,306	9,395	13,931	2,504	3,794	1,946	1,940	1,186	58,945	14,793	1,867	110,896
Dec 2016	21,259	8,194	10,584	15,832	2,759	4,276	2,145	2,369	1,083	66,335	16,257	1,340	125,824

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	DIVERSITY	WESTERN	DOM	DIVERSITY	PJM RTO
Jan 2017	22,889	8,778	10,657	15,661	2,901	4,489	2,180	2,634	1,199	68,990	18,063	1,075	132,482
Feb 2017	21,765	8,416	10,517	15,389	2,796	4,309	2,115	2,397	1,591	66,113	16,685	673	126,550
Mar 2017	20,806	8,012	9,796	14,081	2,594	3,976	2,002	2,090	1,817	61,540	16,415	1,977	115,740
Apr 2017	19,179	7,314	9,284	13,795	2,471	3,916	2,067	1,704	2,651	57,079	16,163	2,442	107,929
May 2017	19,840	7,586	10,499	16,948	2,797	4,487	2,359	1,578	2,489	63,605	17,508	3,973	121,445
Jun 2017	22,468	8,664	12,549	20,801	3,238	5,231	2,825	1,856	1,265	76,367	19,210	4,114	146,155
Jul 2017	23,309	9,014	13,004	22,216	3,453	5,500	2,918	1,947	1,589	79,772	20,052	3,411	154,149
Aug 2017	23,063	8,824	12,667	21,599	3,384	5,442	2,851	1,931	896	78,865	19,711	3,690	149,900
Sep 2017	20,867	7,921	11,067	18,269	2,949	4,803	2,491	1,718	1,697	68,388	17,925	4,174	129,761
Oct 2017	18,771	7,159	9,103	14,136	2,465	3,984	2,023	1,674	2,314	57,001	15,763	2,827	108,770
Nov 2017	19,788	7,543	9,493	14,164	2,545	3,867	1,964	1,964	1,251	60,077	15,460	2,064	112,969
Dec 2017	21,597	8,404	10,649	16,051	2,805	4,317	2,153	2,400	1,226	67,150	16,740	1,082	127,831

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	DIVERSITY	WESTERN	DOM	DIVERSITY	PJM RTO
Jan 2018	23,295	9,009	10,747	15,940	2,955	4,549	2,195	2,665	1,306	70,049	18,622	1,036	134,645
Feb 2018	22,146	8,630	10,596	15,650	2,850	4,353	2,126	2,423	1,786	66,988	17,187	598	128,586
Mar 2018	21,200	8,151	9,873	14,282	2,640	4,041	2,016	2,112	1,851	62,464	17,019	2,198	117,200
Apr 2018	19,944	7,486	9,344	14,213	2,556	4,077	2,189	1,731	1,896	59,644	16,756	453	113,782
May 2018	20,211	7,719	10,597	17,183	2,844	4,562	2,381	1,594	2,513	64,578	18,223	4,015	123,572
Jun 2018	22,771	8,783	12,646	20,934	3,277	5,295	2,840	1,866	1,324	77,088	19,679	4,224	147,487
Jul 2018	23,584	9,127	13,089	22,438	3,496	5,566	2,938	1,960	1,564	80,634	20,499	3,414	155,913
Aug 2018	23,351	8,945	12,762	21,770	3,425	5,502	2,873	1,943	946	79,625	20,167	4,827	150,331
Sep 2018	21,090	8,030	11,100	18,353	2,969	4,813	2,496	1,731	1,892	68,690	18,459	4,575	130,600
Oct 2018	19,427	7,388	9,156	14,541	2,567	4,051	2,180	1,696	1,339	59,667	16,313	2,543	112,755
Nov 2018	20,134	7,723	9,538	14,290	2,574	3,916	1,985	1,973	1,179	60,954	16,011	2,401	114,369
Dec 2018	22,038	8,577	10,832	16,296	2,857	4,388	2,186	2,439	1,382	68,231	17,207	1,176	129,648

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.

Table B-6

MONTHLY PEAK FORECAST (MW) FOR FE-EAST AND PLGRP

	FE_EAST	PLGRP
Jan 2016	9,095	7,387
Feb 2016	8,878	7,000
Mar 2016	7,905	6,423
Apr 2016	7,488	5,866
May 2016	8,691	5,971
Jun 2016	10,893	6,975
Jul 2016	11,538	7,336
Aug 2016	10,955	7,036
Sep 2016	9,361	6,339
Oct 2016	7,605	5,802
Nov 2016	7,919	6,297
Dec 2016	9,132	7,003

	FE_EAST	PLGRP
Jan 2017	9,229	7,476
Feb 2017	8,983	7,084
Mar 2017	7,962	6,499
Apr 2017	7,511	5,886
May 2017	8,861	6,054
Jun 2017	10,990	7,054
Jul 2017	11,655	7,417
Aug 2017	11,038	7,079
Sep 2017	9,443	6,426
Oct 2017	7,812	5,932
Nov 2017	8,033	6,401
Dec 2017	9,208	7,073

	FE_EAST	PLGRP
Jan 2018	9,335	7,566
Feb 2018	9,103	7,173
Mar 2018	8,032	6,578
Apr 2018	7,656	6,016
May 2018	8,963	6,129
Jun 2018	11,072	7,107
Jul 2018	11,762	7,487
Aug 2018	11,107	7,149
Sep 2018	9,511	6,489
Oct 2018	7,966	6,096
Nov 2018	8,095	6,448
Dec 2018	9,314	7,158

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.

Table B-7

PJM MID-ATLANTIC REGION LOAD MANAGEMENT
PLACED UNDER PJM COORDINATION - SUMMER (MW)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
AE																
LIMITED	43	43														
EXTENDED SUMMER	61	61														
ANNUAL	0	0														
BASE			105	105												
CAPACITY PERFORMANCE			0	0	38	38	38	38	38	38	38	38	38	38	38	38
TOTAL LOAD MANAGEMENT	104	104	105	105	38	38	38	38	38	38	38	38	38	38	38	38
BGE																
LIMITED	617	622														
EXTENDED SUMMER	62	62														
ANNUAL	4	4														
BASE			691	691												
CAPACITY PERFORMANCE			4	4	259	258	258	259	261	263	264	264	264	267	268	269
TOTAL LOAD MANAGEMENT	683	688	695	695	259	258	258	259	261	263	264	264	264	267	268	269
DPL																
LIMITED	149	150														
EXTENDED SUMMER	85	86														
ANNUAL	0	0														
BASE			238	238												
CAPACITY PERFORMANCE			0	0	88	88	88	88	88	89	89	89	89	90	90	90
TOTAL LOAD MANAGEMENT	234	236	238	238	88	88	88	88	88	89	89	89	89	90	90	90
JCPL																
LIMITED	116	116														
EXTENDED SUMMER	33	34														
ANNUAL	0	0														
BASE			152	152												
CAPACITY PERFORMANCE			0	0	56	56	56	56	56	56	56	57	56	57	57	57
TOTAL LOAD MANAGEMENT	149	150	152	152	56	56	56	56	56	56	56	57	56	57	57	57
METED																
LIMITED	166	169														
EXTENDED SUMMER	51	51														
ANNUAL	0	0														
BASE			223	225												
CAPACITY PERFORMANCE			0	0	83	83	83	83	85	85	86	87	87	88	90	92
TOTAL LOAD MANAGEMENT	217	220	223	225	83	83	83	83	85	85	86	87	87	88	90	92

DR Forecast accounts for the transition from Limited, Extended Summer and Annual DR to Base and Capacity Performance (CP) DR in Delivery Year (DY) 2018, and then to only CP DR in DY 2020.
DR Forecast is based on the average ratio of committed DR (by DR product) to past forecasted peak in the last 3 DYs (2013, 2014 and 2015) multiplied by the forecasted summer peaks in Table B-1.
The following assumptions are made to forecast the new products that begin in DY 2018:
-For DYs 2018 and 2019, Limited and Extended Summer DR are assumed to become Base DR while Annual DR is assumed to become CP DR.
-For DY 2020 and beyond, Annual DR is assumed to become CP DR. In addition, a portion of Base DR is assumed to become CP DR. This portion is computed based on the ratio of Coupled Base DR Offers to Total Cleared Base DR Offers from the 2018 BRA results.
Full transition to Base and CP DR for regions with FRR DR (AEP, DEOK) is completed in DY 2019.
Winter load management is equal to Annual for Delivery Years 2016 and 2017. After those Delivery Years, winter load management is equal to Capacity Performance.

Table B-7 (Continued)

PJM MID-ATLANTIC REGION LOAD MANAGEMENT
PLACED UNDER PJM COORDINATION - SUMMER (MW)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
PECO																
LIMITED	314	319														
EXTENDED SUMMER	103	104														
ANNUAL	0	0														
BASE			427	429												
CAPACITY PERFORMANCE			0	0	158	158	159	159	161	162	164	164	166	167	169	171
TOTAL LOAD MANAGEMENT	417	423	427	429	158	158	159	159	161	162	164	164	166	167	169	171
PENLC																
LIMITED	224	225														
EXTENDED SUMMER	53	53														
ANNUAL	0	0														
BASE			278	279												
CAPACITY PERFORMANCE			0	0	102	102	102	102	102	102	103	103	103	103	103	103
TOTAL LOAD MANAGEMENT	277	278	278	279	102	102	102	102	102	102	103	103	103	103	103	103
PEPCO																
LIMITED	209	210														
EXTENDED SUMMER	238	240														
ANNUAL	0	0														
BASE			452	454												
CAPACITY PERFORMANCE			0	0	168	167	167	168	168	169	171	170	171	171	173	175
TOTAL LOAD MANAGEMENT	447	450	452	454	168	167	167	168	168	169	171	170	171	171	173	175
PL																
LIMITED	501	506														
EXTENDED SUMMER	141	143														
ANNUAL	1	1														
BASE			655	658												
CAPACITY PERFORMANCE			1	1	242	243	243	244	246	247	249	251	252	254	256	258
TOTAL LOAD MANAGEMENT	643	650	656	659	242	243	243	244	246	247	249	251	252	254	256	258
PS																
LIMITED	277	280														
EXTENDED SUMMER	87	88														
ANNUAL	16	16														
BASE			370	370												
CAPACITY PERFORMANCE			16	16	152	152	151	151	151	152	152	152	152	152	153	154
TOTAL LOAD MANAGEMENT	380	384	386	386	152	152	151	151	151	152	152	152	152	152	153	154

DR Forecast accounts for the transition from Limited, Extended Summer and Annual DR to Base and Capacity Performance (CP) DR in Delivery Year (DY) 2018, and then to only CP DR in DY 2020.
DR Forecast is based on the average ratio of committed DR (by DR product) to past forecasted peak in the last 3 DYs (2013, 2014 and 2015) multiplied by the forecasted summer peaks in Table B-1.
The following assumptions are made to forecast the new products that begin in DY 2018:
-For DYs 2018 and 2019, Limited and Extended Summer DR are assumed to become Base DR while Annual DR is assumed to become CP DR.
-For DY 2020 and beyond, Annual DR is assumed to become CP DR. In addition, a portion of Base DR is assumed to become CP DR. This portion is computed based on the ratio of Coupled Base DR Offers to Total Cleared Base DR Offers from the 2018 BRA results.
Full transition to Base and CP DR for regions with FRR DR (AEP, DEOK) is completed in DY 2019.
Winter load management is equal to Annual for Delivery Years 2016 and 2017. After those Delivery Years, winter load management is equal to Capacity Performance.

Table B-7 (Continued)

**PJM MID-ATLANTIC REGION LOAD MANAGEMENT
PLACED UNDER PJM COORDINATION - SUMMER (MW)**

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
RECO																
LIMITED	4	4														
EXTENDED SUMMER	1	1														
ANNUAL	0	0														
BASE			5	5												
CAPACITY PERFORMANCE			0	0	2	2	2	2	2	2	2	2	2	2	2	2
TOTAL LOAD MANAGEMENT	5	5	5	5	2	2	2	2	2	2	2	2	2	2	2	2
UGI																
LIMITED	0	0														
EXTENDED SUMMER	0	0														
ANNUAL	0	0														
BASE			0	0												
CAPACITY PERFORMANCE			0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PJM MID-ATLANTIC																
LIMITED	2,620	2,644														
EXTENDED SUMMER	915	923														
ANNUAL	21	21														
BASE			3,596	3,606												
CAPACITY PERFORMANCE			21	21	1,348	1,347	1,347	1,350	1,358	1,365	1,374	1,377	1,380	1,389	1,399	1,409
TOTAL LOAD MANAGEMENT	3,556	3,588	3,617	3,627	1,348	1,347	1,347	1,350	1,358	1,365	1,374	1,377	1,380	1,389	1,399	1,409

DR Forecast accounts for the transition from Limited, Extended Summer and Annual DR to Base and Capacity Performance (CP) DR in Delivery Year (DY) 2018, and then to only CP DR in DY 2020.
DR Forecast is based on the average ratio of committed DR (by DR product) to past forecasted peak in the last 3 DYs (2013, 2014 and 2015) multiplied by the forecasted summer peaks in Table B-1.
The following assumptions are made to forecast the new products that begin in DY 2018:
- -For DYs 2018 and 2019, Limited and Extended Summer DR are assumed to become Base DR while Annual DR is assumed to become CP DR.
- -For DY 2020 and beyond, Annual DR is assumed to become CP DR. In addition, a portion of Base DR is assumed to become CP DR. This portion is computed based on the ratio of Coupled Base DR Offers to Total Cleared Base DR Offers from the 2018 BRA results.

Full transition to Base and CP DR for regions with FRR DR (AEP, DEOK) is completed in DY 2019.
Winter load management is equal to Annual for Delivery Years 2016 and 2017. After those Delivery Years, winter load management is equal to Capacity Performance.

Table B-7 (Continued)

PJM WESTERN REGION AND PJM SOUTHERN REGION LOAD MANAGEMENT
PLACED UNDER PJM COORDINATION - SUMMER (MW)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
AEP																
LIMITED	1,250	1,266	421													
EXTENDED SUMMER	71	72	0													
ANNUAL	39	40	0													
BASE			933	1,367												
CAPACITY PERFORMANCE			40	40	543	546	550	553	559	563	567	572	577	583	589	595
TOTAL LOAD MANAGEMENT	1,360	1,378	1,394	1,407	543	546	550	553	559	563	567	572	577	583	589	595
APS																
LIMITED	459	468														
EXTENDED SUMMER	149	153														
ANNUAL	6	6														
BASE			629	635												
CAPACITY PERFORMANCE			6	6	241	241	242	243	245	247	249	250	251	253	255	257
TOTAL LOAD MANAGEMENT	614	627	635	641	241	241	242	243	245	247	249	250	251	253	255	257
ATSI																
LIMITED	525	528														
EXTENDED SUMMER	235	237														
ANNUAL	26	26														
BASE			770	773												
CAPACITY PERFORMANCE			26	26	310	311	312	312	314	315	317	318	320	322	324	326
TOTAL LOAD MANAGEMENT	786	791	796	799	310	311	312	312	314	315	317	318	320	322	324	326
COMED																
LIMITED	773	779														
EXTENDED SUMMER	327	331														
ANNUAL	7	7														
BASE			1,122	1,131												
CAPACITY PERFORMANCE			7	7	423	425	428	430	434	438	441	445	448	451	457	463
TOTAL LOAD MANAGEMENT	1,107	1,117	1,129	1,138	423	425	428	430	434	438	441	445	448	451	457	463
DAYTON																
LIMITED	106	108														
EXTENDED SUMMER	8	8														
ANNUAL	7	7														
BASE			117	118												
CAPACITY PERFORMANCE			7	7	51	51	51	51	52	52	53	53	53	54	54	54
TOTAL LOAD MANAGEMENT	121	123	124	125	51	51	51	51	52	52	53	53	53	54	54	54

DR Forecast accounts for the transition from Limited, Extended Summer and Annual DR to Base and Capacity Performance (CP) DR in Delivery Year (DY) 2018, and then to only CP DR in DY 2020.
DR Forecast is based on the average ratio of committed DR (by DR product) to past forecasted peak in the last 3 DYs (2013, 2014 and 2015) multiplied by the forecasted summer peaks in Table B-1.
The following assumptions are made to forecast the new products that begin in DY 2018:
-For DYs 2018 and 2019, Limited and Extended Summer DR are assumed to become Base DR while Annual DR is assumed to become CP DR.
-For DY 2020 and beyond, Annual DR is assumed to become CP DR. In addition, a portion of Base DR is assumed to become CP DR. This portion is computed based on the ratio of Coupled Base DR Offers to Total Cleared Base DR Offers from the 2018 BRA results.
Full transition to Base and CP DR for regions with FRR DR (AEP, DEOK) is completed in DY 2019.
Winter load management is equal to Annual for Delivery Years 2016 and 2017. After those Delivery Years, winter load management is equal to Capacity Performance.

Table B-7 (Continued)

PJM WESTERN REGION AND PJM SOUTHERN REGION LOAD MANAGEMENT PLACED UNDER PJM COORDINATION - SUMMER (MW)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
DEOK																
LIMITED	183	186	37													
EXTENDED SUMMER	49	49	0													
ANNUAL	0	0	0													
BASE			201	240												
CAPACITY PERFORMANCE			0	0	88	89	89	90	91	91	92	93	93	94	95	96
TOTAL LOAD MANAGEMENT	232	235	238	240	88	89	89	90	91	91	92	93	93	94	95	96
DLCO																
LIMITED	84	85														
EXTENDED SUMMER	20	20														
ANNUAL	1	1														
BASE			106	106												
CAPACITY PERFORMANCE			1	1	40	40	40	40	40	40	40	40	41	41	41	41
TOTAL LOAD MANAGEMENT	105	106	107	107	40	40	40	40	40	40	40	40	41	41	41	41
EKPC																
LIMITED	111	112														
EXTENDED SUMMER	0	0														
ANNUAL	0	0														
BASE			113	114												
CAPACITY PERFORMANCE			0	0	42	42	42	43	43	43	43	44	44	44	44	44
TOTAL LOAD MANAGEMENT	111	112	113	114	42	42	42	43	43	43	43	44	44	44	44	44
PJM WESTERN																
LIMITED	3,491	3,532	458													
EXTENDED SUMMER	859	870	0													
ANNUAL	86	87	0													
BASE			3,991	4,484												
CAPACITY PERFORMANCE			87	87	1,738	1,745	1,754	1,762	1,778	1,789	1,802	1,815	1,827	1,842	1,859	1,876
TOTAL LOAD MANAGEMENT	4,436	4,489	4,536	4,571	1,738	1,745	1,754	1,762	1,778	1,789	1,802	1,815	1,827	1,842	1,859	1,876

DR Forecast accounts for the transition from Limited, Extended Summer and Annual DR to Base and Capacity Performance (CP) DR in Delivery Year (DY) 2018, and then to only CP DR in DY 2020.
DR Forecast is based on the average ratio of committed DR (by DR product) to past forecasted peak in the last 3 DYs (2013, 2014 and 2015) multiplied by the forecasted summer peaks in Table B-1.
The following assumptions are made to forecast the new products that begin in DY 2018:
-For DYs 2018 and 2019, Limited and Extended Summer DR are assumed to become Base DR while Annual DR is assumed to become CP DR.
-For DY 2020 and beyond, Annual DR is assumed to become CP DR. In addition, a portion of Base DR is assumed to become CP DR. This portion is computed based on the ratio of Coupled Base DR Offers to Total Cleared Base DR Offers from the 2018 BRA results.
Full transition to Base and CP DR for regions with FRR DR (AEP, DEOK) is completed in DY 2019.
Winter load management is equal to Annual for Delivery Years 2016 and 2017. After those Delivery Years, winter load management is equal to Capacity Performance.

Table B-7 (Continued)

**PJM WESTERN REGION AND PJM SOUTHERN REGION LOAD MANAGEMENT
PLACED UNDER PJM COORDINATION - SUMMER (MW)**

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
DOM																
LIMITED	695	714														
EXTENDED SUMMER	59	60														
ANNUAL	31	32														
BASE			791	804												
CAPACITY PERFORMANCE			33	33	330	332	335	338	342	345	348	351	355	358	362	366
TOTAL LOAD MANAGEMENT	785	806	824	837	330	332	335	338	342	345	348	351	355	358	362	366
PJM RTO																
LIMITED	6,806	6,890	458													
EXTENDED SUMMER	1,833	1,853	0													
ANNUAL	138	140	0													
BASE			8,378	8,894												
CAPACITY PERFORMANCE			141	141	3,416	3,424	3,436	3,450	3,478	3,499	3,524	3,543	3,562	3,589	3,620	3,651
TOTAL LOAD MANAGEMENT	8,777	8,883	8,977	9,035	3,416	3,424	3,436	3,450	3,478	3,499	3,524	3,543	3,562	3,589	3,620	3,651

DR Forecast accounts for the transition from Limited, Extended Summer and Annual DR to Base and Capacity Performance (CP) DR in Delivery Year (DY) 2018, and then to only CP DR in DY 2020.
DR Forecast is based on the average ratio of committed DR (by DR product) to past forecasted peak in the last 3 DYs (2013, 2014 and 2015) multiplied by the forecasted summer peaks in Table B-1.

The following assumptions are made to forecast the new products that begin in DY 2018:

-For DYs 2018 and 2019, Limited and Extended Summer DR are assumed to become Base DR while Annual DR is assumed to become CP DR.

-For DY 2020 and beyond, Annual DR is assumed to become CP DR. In addition, a portion of Base DR is assumed to become CP DR. This portion is computed based on the ratio of Coupled Base DR Offers to Total Cleared Base DR Offers from the 2018 BRA results.

Full transition to Base and CP DR for regions with FRR DR (AEP, DEOK) is completed in DY 2019.
Winter load management is equal to Annual for Delivery Years 2016 and 2017. After those Delivery Years, winter load management is equal to Capacity Performance.

Table B-8

DISTRIBUTED SOLAR ADJUSTMENTS TO SUMMER PEAK LOAD (MW) FOR EACH PJM ZONE AND RTO 2016-2031

Zone	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
AE	69	74	75	77	78	80	83	86	90	97	107	118	130	144	159	173
BGE	36	47	59	68	72	73	74	76	78	82	87	94	103	116	131	146
DPL	40	47	57	66	71	77	86	96	104	112	120	130	142	158	178	205
JCPL	100	107	110	112	115	118	122	127	134	145	161	180	200	223	246	270
METED	10	11	12	13	14	15	16	16	17	18	18	19	20	21	22	23
PECO	13	15	18	20	23	25	26	28	29	31	32	34	35	37	40	43
PENLC	4	6	8	9	11	13	14	15	16	17	18	19	20	22	23	25
PEPCO	24	32	40	46	49	50	52	53	55	58	61	66	72	81	90	100
PL	29	32	35	38	42	44	46	48	50	53	55	57	59	61	65	69
PS	125	136	141	145	149	154	160	169	180	197	220	249	280	315	351	387
RECO	3	3	3	4	4	4	4	4	5	5	6	7	8	9	11	12
UGI	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1
AEP	11	16	21	27	34	41	50	59	68	78	88	96	105	114	125	137
APS	14	18	23	28	31	33	36	38	41	44	48	52	57	63	70	78
ATSI	18	22	27	32	37	43	48	53	59	65	71	73	74	76	77	80
COMED	17	22	26	30	33	39	46	53	61	69	77	84	92	100	108	116
DAYTON	3	4	5	6	7	9	10	11	12	13	15	15	15	16	16	16
DEOK	4	5	7	8	9	11	13	14	16	18	20	21	21	21	22	22
DLCO	2	3	4	5	6	7	8	8	9	10	10	11	11	12	13	14
EKPC	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	2
DOM	51	73	86	104	126	149	177	208	240	273	307	343	382	423	469	518
PJM RTO	574	676	759	839	914	986	1,070	1,165	1,267	1,385	1,523	1,669	1,829	2,013	2,217	2,441

Note: Adjustment values presented here are reflected in all summer peak forecast values.
Adjustments reflect the impact of historical distributed solar generation and forecasted distributed solar generation.

Table B-9

ADJUSTMENTS TO SUMMER PEAK LOAD (MW) FOR EACH PJM ZONE AND RTO 2016 - 2031

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
AE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BGE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DPL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
JCPL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
METED	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PECO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PENLC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PEPCO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RECO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
UGI	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AEP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
APS	120	220	250	280	280	270	260	260	250	240	230	230	220	210	210	200
ATSI	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
COMED	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DAYTON	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEOK	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DLCO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EKPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DOM	240	410	560	680	730	810	860	900	930	960	990	1,010	1,020	1,040	1,050	1,050
PJM RTO	360	630	810	960	1,010	1,080	1,120	1,160	1,180	1,200	1,220	1,240	1,240	1,250	1,260	1,250

Notes:
Adjustment values presented here are reflected in Tables B-1 through B-6 and Tables B-10, B-11 and B12.
Adjustments are large, unanticipated load changes deemed by PJM to not be captured in the forecast model.

Table B-10

SUMMER COINCIDENT PEAK LOAD (MW) FOR
EACH PJM ZONE, LOCATIONAL DELIVERABILITY AREA AND RTO
2016 - 2031

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
AE	2,435	2,442	2,447	2,445	2,430	2,418	2,414	2,415	2,415	2,414	2,409	2,405	2,404	2,402	2,392	2,389
BGE	6,663	6,716	6,765	6,758	6,778	6,763	6,773	6,813	6,833	6,894	6,917	6,924	6,964	7,014	7,013	7,072
DPL	3,838	3,878	3,907	3,916	3,917	3,908	3,912	3,926	3,941	3,966	3,977	3,982	4,003	4,023	4,027	4,038
JCPL	5,749	5,820	5,883	5,891	5,859	5,860	5,856	5,871	5,886	5,905	5,916	5,946	5,958	5,996	5,993	6,020
METED	2,824	2,856	2,907	2,937	2,931	2,940	2,950	2,960	3,009	3,034	3,058	3,087	3,100	3,148	3,183	3,211
PECO	8,255	8,363	8,454	8,497	8,500	8,491	8,527	8,587	8,646	8,694	8,796	8,837	8,923	9,010	9,075	9,144
PENLC	2,764	2,774	2,776	2,779	2,781	2,769	2,768	2,772	2,773	2,772	2,786	2,785	2,790	2,794	2,798	2,799
PEPCO	6,288	6,333	6,353	6,387	6,415	6,404	6,384	6,407	6,426	6,471	6,512	6,525	6,529	6,560	6,581	6,631
PL	6,906	6,982	7,051	7,083	7,059	7,073	7,096	7,128	7,167	7,205	7,243	7,303	7,350	7,412	7,452	7,501
PS	9,719	9,787	9,863	9,868	9,841	9,818	9,810	9,820	9,805	9,830	9,843	9,869	9,879	9,896	9,875	9,907
RECO	388	391	393	393	392	391	391	391	391	392	392	392	393	393	393	393
UGI	180	182	183	183	182	181	181	181	182	182	183	183	184	184	185	185
AEP	22,139	22,439	22,706	22,901	22,876	23,017	23,164	23,369	23,574	23,723	23,891	24,119	24,362	24,594	24,809	24,990
APS	8,495	8,696	8,812	8,891	8,895	8,920	8,958	9,022	9,074	9,132	9,184	9,245	9,314	9,384	9,442	9,511
ATSI	12,396	12,476	12,545	12,617	12,581	12,618	12,649	12,692	12,767	12,801	12,845	12,922	12,977	13,057	13,143	13,193
COMED	21,212	21,456	21,693	21,855	21,864	21,976	22,120	22,271	22,451	22,623	22,782	22,994	23,199	23,347	23,603	23,799
DAYTON	3,229	3,276	3,317	3,344	3,330	3,341	3,359	3,385	3,416	3,435	3,456	3,482	3,514	3,550	3,577	3,600
DEOK	5,193	5,258	5,329	5,374	5,386	5,402	5,432	5,477	5,527	5,571	5,605	5,643	5,698	5,754	5,807	5,854
DLCO	2,772	2,796	2,818	2,827	2,817	2,819	2,822	2,831	2,840	2,848	2,858	2,874	2,889	2,905	2,917	2,928
EKPC	1,858	1,880	1,895	1,906	1,908	1,916	1,918	1,938	1,952	1,960	1,968	1,980	1,994	2,007	2,020	2,028
DOM	18,827	19,347	19,813	20,104	20,145	20,332	20,503	20,716	20,916	21,094	21,269	21,491	21,723	21,963	22,127	22,274
PJM RTO	152,130	154,148	155,910	156,956	156,887	157,357	157,987	158,972	159,991	160,946	161,890	162,988	164,147	165,393	166,412	167,467
PJM MID-ATLANTIC	56,009	56,524	56,982	57,137	57,085	57,016	57,062	57,271	57,474	57,759	58,032	58,238	58,477	58,832	58,967	59,290
EASTERN MID-ATLANTIC	30,384	30,681	30,947	31,010	30,939	30,886	30,910	31,010	31,084	31,201	31,333	31,431	31,560	31,720	31,755	31,891
SOUTHERN MID-ATLANTIC	12,951	13,049	13,118	13,145	13,193	13,167	13,157	13,220	13,259	13,365	13,429	13,449	13,493	13,574	13,594	13,703

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.
Load values for Zones and Locational Deliverability Areas are coincident with the PJM RTO peak.
This table will be used for the Reliability Pricing Model.
Summer season indicates peak from June, July, August.

Table B-11

PJM CONTROL AREA - JANUARY 2016
SUMMER TOTAL INTERNAL DEMAND FORECAST (MW) FOR EACH NERC REGION
2016 - 2026

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Annual Growth Rate (10 yr)
PJM - RELIABILITY FIRST												
TOTAL INTERNAL DEMAND	130,676	132,150	133,454	134,171	134,028	134,319	134,753	135,548	136,330	137,062	137,809	0.5%
% TOTAL		1.1%	1.0%	0.5%	-0.1%	0.2%	0.3%	0.6%	0.6%	0.5%	0.5%	
CONTRACTUALLY INTERRUPTIBLE	7,604	7,686	7,759	7,802	2,938	2,943	2,952	2,962	2,986	3,003	3,025	
DIRECT CONTROL	277	279	281	282	106	107	107	107	107	108	108	
TOTAL LOAD MANAGEMENT	7,881	7,965	8,040	8,084	3,044	3,050	3,059	3,069	3,093	3,111	3,133	
NET INTERNAL DEMAND	122,795	124,185	125,414	126,087	130,984	131,269	131,694	132,479	133,237	133,951	134,676	0.9%
% NET		1.1%	1.0%	0.5%	3.9%	0.2%	0.3%	0.6%	0.6%	0.5%	0.5%	
PJM - SERC												
TOTAL INTERNAL DEMAND	21,455	21,999	22,459	22,787	22,859	23,039	23,233	23,427	23,661	23,885	24,082	1.2%
% TOTAL		2.5%	2.1%	1.5%	0.3%	0.8%	0.8%	0.8%	1.0%	0.9%	0.8%	
CONTRACTUALLY INTERRUPTIBLE	792	811	828	840	329	330	333	337	340	343	345	
DIRECT CONTROL	104	107	109	111	43	44	44	44	45	45	46	
TOTAL LOAD MANAGEMENT	896	918	937	951	372	374	377	381	385	388	391	
NET INTERNAL DEMAND	20,559	21,081	21,522	21,836	22,487	22,665	22,856	23,046	23,276	23,497	23,691	1.4%
% NET		2.5%	2.1%	1.5%	3.0%	0.8%	0.8%	0.8%	1.0%	0.9%	0.8%	
PJM RTO												
TOTAL INTERNAL DEMAND	152,131	154,149	155,913	156,958	156,887	157,358	157,986	158,975	159,991	160,947	161,891	0.6%
% TOTAL		1.3%	1.1%	0.7%	-0.0%	0.3%	0.4%	0.6%	0.6%	0.6%	0.6%	
CONTRACTUALLY INTERRUPTIBLE	8,396	8,497	8,587	8,642	3,266	3,274	3,285	3,299	3,326	3,346	3,370	
DIRECT CONTROL	381	386	390	393	150	150	151	151	152	153	154	
TOTAL LOAD MANAGEMENT	8,777	8,883	8,977	9,035	3,416	3,424	3,436	3,450	3,478	3,499	3,524	
NET INTERNAL DEMAND	143,354	145,266	146,936	147,923	153,471	153,934	154,550	155,525	156,513	157,448	158,367	1.0%
% NET		1.3%	1.1%	0.7%	3.8%	0.3%	0.4%	0.6%	0.6%	0.6%	0.6%	

Notes:
Total Internal Demand = projected PJM seasonal peak load at normal peak weather conditions in the absence of any load reductions due to load management, voltage reductions or voluntary curtailments.
Contractually Interruptible = Firm Service Level + Guaranteed Load Drop
The above forecasts incorporate all load in the PJM Control Area, including members and non-members.
All average growth rates are calculated from the first year of the forecast (2016).

Table B-11 (Continued)

PJM CONTROL AREA - JANUARY 2016
SUMMER TOTAL INTERNAL DEMAND FORECAST (MW) FOR EACH NERC REGION
2027 - 2031

	2027	2028	2029	2030	2031	Annual Growth Rate (15 yr)
PJM - RELIABILITY FIRST						
TOTAL INTERNAL DEMAND	138,680	139,616	140,622	141,415	142,280	0.6%
% TOTAL	0.6%	0.7%	0.7%	0.6%	0.6%	
CONTRACTUALLY INTERRUPTIBLE	3,039	3,054	3,078	3,104	3,130	
DIRECT CONTROL	109	109	109	110	111	
TOTAL LOAD MANAGEMENT	3,148	3,163	3,187	3,214	3,241	
NET INTERNAL DEMAND	135,532	136,453	137,435	138,201	139,039	0.8%
% NET	0.6%	0.7%	0.7%	0.6%	0.6%	
PJM - SERC						
TOTAL INTERNAL DEMAND	24,308	24,529	24,770	24,997	25,189	1.1%
% TOTAL	0.9%	0.9%	1.0%	0.9%	0.8%	
CONTRACTUALLY INTERRUPTIBLE	349	352	355	359	362	
DIRECT CONTROL	46	47	47	47	48	
TOTAL LOAD MANAGEMENT	395	399	402	406	410	
NET INTERNAL DEMAND	23,913	24,130	24,368	24,591	24,779	1.3%
% NET	0.9%	0.9%	1.0%	0.9%	0.8%	
PJM RTO						
TOTAL INTERNAL DEMAND	162,988	164,145	165,392	166,412	167,469	0.6%
% TOTAL	0.7%	0.7%	0.8%	0.6%	0.6%	
CONTRACTUALLY INTERRUPTIBLE	3,388	3,406	3,433	3,462	3,492	
DIRECT CONTROL	155	156	156	158	159	
TOTAL LOAD MANAGEMENT	3,543	3,562	3,589	3,620	3,651	
NET INTERNAL DEMAND	159,445	160,583	161,803	162,792	163,818	0.9%
% NET	0.7%	0.7%	0.8%	0.6%	0.6%	

Notes:
Total Internal Demand = projected PJM seasonal peak load at normal peak weather conditions in the absence of any load reductions due to load management, voltage reductions or voluntary curtailments.
Contractually Interruptible = Firm Service Level + Guaranteed Load Drop
The above forecasts incorporate all load in the PJM Control Area, including members and non-members.
All average growth rates are calculated from the first year of the forecast (2016).

Table B-12

PJM CONTROL AREA - JANUARY 2016
WINTER TOTAL INTERNAL DEMAND FORECAST (MW) FOR EACH NERC REGION
2015/16 - 2025/26

	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	Annual Growth Rate (10 yr)
PJM - RELIABILITY FIRST												
TOTAL INTERNAL DEMAND	110,210	111,785	113,358	114,337	114,155	114,366	114,984	115,484	116,410	116,964	117,643	0.7%
% TOTAL		1.4%	1.4%	0.9%	-0.2%	0.2%	0.5%	0.4%	0.8%	0.5%	0.6%	
CONTRACTUALLY INTERRUPTIBLE	102	103	103	103	2,938	2,943	2,952	2,962	2,986	3,003	3,025	
DIRECT CONTROL	5	5	5	5	106	107	107	107	107	108	108	
TOTAL LOAD MANAGEMENT	5	5	5	5	106	107	107	107	107	108	108	
NET INTERNAL DEMAND	110,205	111,780	113,353	114,332	114,049	114,259	114,877	115,377	116,303	116,856	117,535	0.6%
% NET		1.4%	1.4%	0.9%	-0.2%	0.2%	0.5%	0.4%	0.8%	0.5%	0.6%	
PJM - SERC												
TOTAL INTERNAL DEMAND	20,033	20,697	21,287	21,742	21,867	22,036	22,279	22,526	22,780	22,998	23,269	1.5%
% TOTAL		3.3%	2.9%	2.1%	0.6%	0.8%	1.1%	1.1%	1.1%	1.0%	1.2%	
CONTRACTUALLY INTERRUPTIBLE	27	28	29	29	329	330	333	337	340	343	345	
DIRECT CONTROL	4	4	4	4	43	44	44	44	45	45	46	
TOTAL LOAD MANAGEMENT	31	32	33	33	372	374	377	381	385	388	391	
NET INTERNAL DEMAND	20,002	20,665	21,254	21,709	21,495	21,662	21,902	22,145	22,395	22,610	22,878	1.4%
% NET		3.3%	2.9%	2.1%	-1.0%	0.8%	1.1%	1.1%	1.1%	1.0%	1.2%	
PJM RTO												
TOTAL INTERNAL DEMAND	130,243	132,482	134,645	136,079	136,022	136,402	137,263	138,010	139,190	139,962	140,912	0.8%
% TOTAL		1.7%	1.6%	1.1%	-0.0%	0.3%	0.6%	0.5%	0.9%	0.6%	0.7%	
CONTRACTUALLY INTERRUPTIBLE	130	132	132	132	3,266	3,274	3,285	3,299	3,326	3,346	3,370	
DIRECT CONTROL	8	8	9	9	150	150	151	151	152	153	154	
TOTAL LOAD MANAGEMENT	138	140	141	141	3,416	3,424	3,436	3,450	3,478	3,499	3,524	
NET INTERNAL DEMAND	130,105	132,342	134,504	135,938	132,606	132,978	133,827	134,560	135,712	136,463	137,388	0.5%
% NET		1.7%	1.6%	1.1%	-2.5%	0.3%	0.6%	0.5%	0.9%	0.6%	0.7%	

Notes:
Total Internal Demand = projected PJM seasonal peak load at normal peak weather conditions in the absence of any load reductions due to load management, voltage reductions or voluntary curtailments.
Contractually Interruptible = Firm Service Level + Guaranteed Load Drop
The above forecasts incorporate all load in the PJM Control Area, including members and non-members.
All average growth rates are calculated from the first year of the forecast (2015/16).

Table B-12 (Continued)

PJM CONTROL AREA - JANUARY 2016
WINTER TOTAL INTERNAL DEMAND FORECAST (MW) FOR EACH NERC REGION
2026/27 - 2030/31

	26/27	27/28	28/29	29/30	30/31	Annual Growth Rate (15 yr)
PJM - RELIABILITY FIRST						
TOTAL INTERNAL DEMAND	118,458	119,353	119,860	120,993	121,705	0.7%
% TOTAL	0.7%	0.8%	0.4%	0.9%	0.6%	
CONTRACTUALLY INTERRUPTIBLE	3,039	3,054	3,078	3,104	3,130	
DIRECT CONTROL	109	109	109	110	111	
TOTAL LOAD MANAGEMENT	109	109	109	110	111	
NET INTERNAL DEMAND	118,349	119,244	119,751	120,883	121,594	0.7%
% NET	0.7%	0.8%	0.4%	0.9%	0.6%	
PJM - SERC						
TOTAL INTERNAL DEMAND	23,529	23,796	24,057	24,310	24,520	1.4%
% TOTAL	1.1%	1.1%	1.1%	1.1%	0.9%	
CONTRACTUALLY INTERRUPTIBLE	349	352	355	359	362	
DIRECT CONTROL	46	47	47	47	48	
TOTAL LOAD MANAGEMENT	395	399	402	406	410	
NET INTERNAL DEMAND	23,134	23,397	23,655	23,904	24,110	1.3%
% NET	1.1%	1.1%	1.1%	1.1%	0.9%	
PJM RTO						
TOTAL INTERNAL DEMAND	141,987	143,149	143,917	145,303	146,225	0.8%
% TOTAL	0.8%	0.8%	0.5%	1.0%	0.6%	
CONTRACTUALLY INTERRUPTIBLE	3,388	3,406	3,433	3,462	3,492	
DIRECT CONTROL	155	156	156	158	159	
TOTAL LOAD MANAGEMENT	3,543	3,562	3,589	3,620	3,651	
NET INTERNAL DEMAND	138,444	139,587	140,328	141,683	142,574	0.6%
% NET	0.8%	0.8%	0.5%	1.0%	0.6%	

Notes:
Total Internal Demand = projected PJM seasonal peak load at normal peak weather conditions in the absence of any load reductions due to load management, voltage reductions or voluntary curtailments.
Contractually Interruptible = Firm Service Level + Guaranteed Load Drop
The above forecasts incorporate all load in the PJM Control Area, including members and non-members.
All average growth rates are calculated from the first year of the forecast (2015/16).

Table C-1

PJM LOCATIONAL DELIVERABILITY AREAS
CENTRAL MID-ATLANTIC: BGE, METED, PEPCO, PL and UGI
SEASONAL PEAKS - MW

BASE (50/50) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2016	18,950	23,491	19,975	21,160
2017	19,162	23,726	20,106	21,455
2018	19,366	23,924	20,239	21,670
2019	19,450	24,038	20,438	21,809
2020	19,286	24,017	20,480	21,762
2021	19,315	24,017	20,494	21,780
2022	19,495	24,085	20,524	21,875
2023	19,587	24,181	20,559	21,934
2024	19,688	24,302	20,711	22,042
2025	19,689	24,439	20,905	22,121
2026	19,769	24,562	21,028	22,222
2027	19,872	24,682	21,153	22,352
2028	20,158	24,832	21,202	22,532
2029	20,295	25,005	21,317	22,637
2030	20,311	25,127	21,505	22,749
2031	20,361	25,275	21,719	22,858

EXTREME WEATHER (90/10) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2016	20,493	24,995	21,534	22,050
2017	20,709	25,237	21,747	22,289
2018	20,908	25,258	21,935	22,545
2019	21,009	25,563	22,036	22,674
2020	20,957	25,628	21,936	22,613
2021	20,981	25,625	22,023	22,628
2022	21,077	25,620	22,097	22,694
2023	21,174	25,761	22,189	22,780
2024	21,284	25,887	22,315	22,888
2025	21,288	26,134	22,432	22,982
2026	21,502	26,260	22,491	23,079
2027	21,643	26,388	22,696	23,201
2028	21,810	26,487	22,849	23,335
2029	21,961	26,463	23,012	23,484
2030	22,064	26,812	23,143	23,589
2031	22,157	27,079	23,282	23,711

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.
Spring season indicates peak from March, April, May.
Summer season indicates peak from June, July, August.
Fall season indicates peak from September, October, November.
Winter season indicates peak from December, January, February.

Table C-2

PJM LOCATIONAL DELIVERABILITY AREAS
WESTERN MID-ATLANTIC: METED, PENLC, PL and UGI
SEASONAL PEAKS - MW

BASE (50/50) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2016	11,286	13,028	11,234	12,734
2017	11,416	13,161	11,370	12,880
2018	11,534	13,268	11,456	13,023
2019	11,588	13,335	11,555	13,094
2020	11,540	13,318	11,550	13,048
2021	11,573	13,334	11,496	13,036
2022	11,609	13,380	11,533	13,097
2023	11,645	13,429	11,570	13,112
2024	11,695	13,501	11,656	13,184
2025	11,734	13,574	11,774	13,231
2026	11,794	13,658	11,818	13,258
2027	11,862	13,749	11,864	13,324
2028	11,935	13,833	11,917	13,420
2029	12,004	13,935	11,966	13,473
2030	12,046	14,023	12,080	13,536
2031	12,095	14,117	12,189	13,602

EXTREME WEATHER (90/10) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2016	11,779	13,822	11,938	13,151
2017	11,870	13,975	12,078	13,304
2018	12,044	14,070	12,193	13,449
2019	12,102	14,155	12,256	13,518
2020	12,053	14,142	12,219	13,467
2021	12,035	14,150	12,239	13,459
2022	12,059	14,203	12,285	13,490
2023	12,105	14,268	12,344	13,531
2024	12,185	14,344	12,420	13,589
2025	12,246	14,471	12,493	13,630
2026	12,306	14,514	12,533	13,676
2027	12,374	14,614	12,642	13,741
2028	12,438	14,717	12,732	13,809
2029	12,516	14,796	12,832	13,881
2030	12,560	14,910	12,908	13,941
2031	12,649	15,063	12,999	13,995

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.
Spring season indicates peak from March, April, May.
Summer season indicates peak from June, July, August.
Fall season indicates peak from September, October, November.
Winter season indicates peak from December, January, February.

Table C-3

PJM LOCATIONAL DELIVERABILITY AREAS
EASTERN MID-ATLANTIC: AE, DPL, JCPL, PECO, PS and RECO
SEASONAL PEAKS - MW

BASE (50/50) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2016	22,695	31,278	25,044	22,194
2017	23,261	31,598	25,263	22,499
2018	23,535	31,716	25,457	22,740
2019	23,641	31,924	25,742	22,922
2020	22,846	31,885	25,796	22,799
2021	22,744	31,709	25,765	22,732
2022	23,277	31,855	25,596	22,781
2023	23,613	31,930	25,622	22,852
2024	23,732	32,019	25,868	22,949
2025	23,583	32,190	26,148	23,004
2026	23,277	32,315	26,261	23,092
2027	23,321	32,292	26,385	23,211
2028	24,095	32,509	26,245	23,365
2029	24,244	32,568	26,376	23,496
2030	24,309	32,732	26,692	23,626
2031	24,200	32,928	26,977	23,706

EXTREME WEATHER (90/10) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2016	26,215	33,422	27,466	22,860
2017	26,534	33,995	27,807	23,140
2018	26,813	34,014	27,937	23,412
2019	26,910	34,304	28,187	23,524
2020	26,824	34,160	28,184	23,417
2021	26,803	34,072	27,961	23,394
2022	26,853	34,069	27,968	23,408
2023	26,935	34,359	28,098	23,475
2024	27,024	34,420	28,335	23,569
2025	27,124	34,604	28,783	23,617
2026	27,235	34,640	28,653	23,704
2027	27,379	34,712	28,603	23,835
2028	27,506	35,019	28,709	23,963
2029	27,625	34,925	28,826	24,095
2030	27,716	35,217	29,204	24,198
2031	27,831	35,447	29,699	24,302

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.
Spring season indicates peak from March, April, May.
Summer season indicates peak from June, July, August.
Fall season indicates peak from September, October, November.
Winter season indicates peak from December, January, February.

Table C-4

PJM LOCATIONAL DELIVERABILITY AREAS
SOUTHERN MID-ATLANTIC: BGE and PEPCO
SEASONAL PEAKS - MW

BASE (50/50) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2016	10,485	13,393	11,363	11,306
2017	10,601	13,491	11,402	11,415
2018	10,727	13,578	11,473	11,491
2019	10,777	13,624	11,555	11,541
2020	10,626	13,662	11,614	11,589
2021	10,625	13,652	11,621	11,604
2022	10,742	13,635	11,620	11,649
2023	10,816	13,678	11,606	11,686
2024	10,902	13,741	11,696	11,700
2025	10,904	13,857	11,816	11,794
2026	10,867	13,911	11,873	11,845
2027	10,914	13,957	11,926	11,905
2028	11,092	13,967	11,897	11,989
2029	11,167	14,043	11,961	12,009
2030	11,218	14,097	12,074	12,069
2031	11,234	14,223	12,183	12,163

EXTREME WEATHER (90/10) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2016	11,509	14,269	12,306	11,802
2017	11,600	14,391	12,405	11,903
2018	11,684	14,426	12,482	12,016
2019	11,727	14,453	12,531	12,067
2020	11,716	14,467	12,455	12,066
2021	11,729	14,484	12,509	12,089
2022	11,761	14,532	12,541	12,124
2023	11,805	14,582	12,600	12,170
2024	11,860	14,586	12,659	12,223
2025	11,905	14,665	12,715	12,272
2026	11,962	14,738	12,710	12,326
2027	12,027	14,810	12,819	12,385
2028	12,089	14,906	12,893	12,452
2029	12,159	14,944	12,962	12,524
2030	12,206	14,981	13,036	12,581
2031	12,249	15,061	13,092	12,642

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.
Spring season indicates peak from March, April, May.
Summer season indicates peak from June, July, August.
Fall season indicates peak from September, October, November.
Winter season indicates peak from December, January, February.

Table D-1

**SUMMER EXTREME WEATHER (90/10) PEAK LOAD FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2016 - 2031**

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
AE	2,637	2,650	2,646	2,658	2,633	2,624	2,623	2,624	2,630	2,633	2,619	2,616	2,620	2,610	2,615	2,616
BGE	7,366	7,431	7,443	7,449	7,460	7,471	7,498	7,532	7,531	7,573	7,615	7,650	7,703	7,721	7,735	7,775
DPL	4,159	4,205	4,219	4,248	4,229	4,236	4,245	4,255	4,273	4,296	4,296	4,318	4,341	4,348	4,371	4,381
JCPL	6,480	6,561	6,588	6,652	6,589	6,586	6,600	6,614	6,654	6,682	6,663	6,694	6,725	6,731	6,791	6,830
METED	3,043	3,119	3,120	3,178	3,179	3,195	3,186	3,239	3,260	3,291	3,321	3,358	3,391	3,387	3,452	3,490
PECO	9,008	9,143	9,208	9,259	9,261	9,295	9,352	9,408	9,443	9,524	9,599	9,687	9,781	9,836	9,916	10,022
PENLC	3,026	3,049	3,046	3,045	3,043	3,038	3,042	3,049	3,043	3,051	3,058	3,063	3,077	3,077	3,080	3,090
PEPCO	6,903	6,960	6,983	7,004	7,007	7,014	7,034	7,050	7,055	7,092	7,123	7,160	7,203	7,223	7,247	7,287
PL	7,556	7,673	7,698	7,725	7,777	7,742	7,794	7,856	7,837	7,973	7,996	8,014	8,117	8,126	8,170	8,317
PS	10,873	10,988	10,901	11,038	11,000	10,883	10,995	11,010	10,973	11,021	11,015	10,947	11,101	10,948	11,073	11,146
RECO	444	448	452	449	448	448	448	448	447	448	449	450	451	453	451	452
UGI	202	205	206	207	205	204	203	204	205	205	205	206	207	208	209	210
DIVERSITY - MID-ATLANTIC(-)	533	610	520	0	412	309	529	603	0	153	456	317	622	525	2	147
PJM MID-ATLANTIC	61,164	61,822	61,990	62,912	62,419	62,427	62,491	62,686	63,351	63,636	63,503	63,846	64,095	64,143	65,108	65,469
FE-EAST	12,422	12,564	12,661	12,714	12,688	12,671	12,699	12,740	12,795	12,860	12,912	12,962	13,028	13,097	13,162	13,248
PLGRP	7,758	7,878	7,903	7,932	7,981	7,946	7,997	8,060	8,042	8,178	8,201	8,220	8,324	8,333	8,379	8,527

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.
Summer season indicates peak from June, July, August.

Table D-1

SUMMER EXTREME WEATHER (90/10) PEAK LOAD FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2016 - 2031

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
AEP	23,944	24,296	24,429	24,609	24,676	24,895	25,097	25,295	25,345	25,578	25,790	26,122	26,380	26,517	26,691	26,960
APS	9,007	9,245	9,358	9,441	9,420	9,460	9,514	9,611	9,645	9,680	9,740	9,824	9,942	10,005	10,060	10,094
ATSI	13,453	13,569	13,619	13,653	13,661	13,705	13,764	13,817	13,833	13,910	13,976	14,060	14,154	14,221	14,265	14,361
COMED	24,083	24,288	24,449	24,691	24,641	24,788	25,042	25,137	25,321	25,537	25,667	25,906	26,159	26,339	26,568	26,821
DAYTON	3,548	3,587	3,618	3,653	3,640	3,657	3,693	3,705	3,732	3,752	3,778	3,810	3,847	3,873	3,906	3,933
DEOK	5,677	5,742	5,786	5,826	5,845	5,880	5,932	5,957	5,990	6,042	6,088	6,143	6,194	6,244	6,288	6,348
DLCO	3,026	3,057	3,068	3,075	3,072	3,074	3,083	3,091	3,091	3,106	3,121	3,138	3,157	3,167	3,177	3,196
EKPC	2,043	2,064	2,072	2,089	2,088	2,101	2,115	2,127	2,140	2,154	2,159	2,178	2,190	2,204	2,218	2,235
DIVERSITY - WESTERN(-)	431	559	236	196	157	335	533	520	203	297	242	423	533	293	162	262
PJM WESTERN	84,350	85,289	86,163	86,841	86,886	87,225	87,707	88,220	88,894	89,462	90,077	90,758	91,490	92,277	93,011	93,686
DOM	20,430	20,989	21,383	21,682	21,783	21,986	22,191	22,384	22,528	22,771	22,976	23,222	23,461	23,661	23,831	24,049
DIVERSITY - INTERREGIONAL(-)	2,250	2,060	1,728	2,335	2,029	2,130	2,332	1,999	2,251	2,315	1,945	2,090	2,028	1,897	2,317	2,376
PJM RTO	163,694	166,040	167,808	169,100	169,059	169,508	170,057	171,291	172,522	173,554	174,611	175,736	177,018	178,184	179,633	180,828

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.
Summer season indicates peak from June, July, August.

Table D-2

WINTER EXTREME WEATHER (90/10) PEAK LOAD FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2015/16 - 2030/31

	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31
AE	1,674	1,679	1,685	1,685	1,671	1,667	1,663	1,662	1,663	1,663	1,665	1,670	1,675	1,679	1,682	1,683
BGE	6,185	6,230	6,281	6,304	6,297	6,309	6,324	6,348	6,372	6,399	6,427	6,455	6,487	6,519	6,546	6,578
DPL	3,565	3,613	3,659	3,682	3,683	3,694	3,707	3,728	3,749	3,773	3,794	3,817	3,841	3,869	3,891	3,919
JCPL	3,846	3,902	3,955	3,993	3,946	3,930	3,934	3,944	3,952	3,940	3,951	3,970	4,011	4,018	4,078	4,061
METED	2,662	2,716	2,758	2,790	2,784	2,782	2,787	2,813	2,830	2,839	2,858	2,876	2,898	2,924	2,967	2,970
PECO	6,841	6,938	7,023	7,064	7,029	7,037	7,059	7,094	7,132	7,164	7,201	7,246	7,292	7,344	7,377	7,424
PENLC	2,871	2,886	2,896	2,906	2,883	2,881	2,883	2,884	2,891	2,883	2,884	2,882	2,890	2,889	2,910	2,893
PEPCO	5,625	5,673	5,735	5,763	5,769	5,783	5,800	5,825	5,851	5,877	5,908	5,940	5,974	6,011	6,037	6,072
PL	7,428	7,509	7,596	7,630	7,606	7,610	7,622	7,649	7,681	7,709	7,743	7,782	7,820	7,867	7,894	7,939
PS	6,818	6,888	6,945	6,979	6,947	6,918	6,930	6,944	6,952	6,950	6,971	7,003	7,035	7,053	7,118	7,100
RECO	236	239	240	241	238	238	239	240	240	238	238	239	240	240	243	240
UGI	201	202	204	204	202	201	201	201	201	201	201	201	201	201	202	202
DIVERSITY - MID-ATLANTIC(-)	578	333	282	332	308	393	328	349	314	407	433	492	318	328	427	439
PJM MID-ATLANTIC	47,374	48,142	48,695	48,909	48,747	48,657	48,821	48,983	49,200	49,229	49,408	49,589	50,046	50,286	50,518	50,642
FE-EAST	9,350	9,462	9,568	9,644	9,568	9,558	9,565	9,592	9,627	9,637	9,675	9,722	9,772	9,829	9,895	9,896
PLGRP	7,628	7,711	7,800	7,834	7,808	7,811	7,823	7,850	7,882	7,909	7,943	7,983	8,021	8,068	8,095	8,140

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.
Winter season indicates peak from December, January, February.

Table D-2

WINTER EXTREME WEATHER (90/10) PEAK LOAD FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2015/16 - 2030/31

	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31
AEP	23,839	24,231	24,701	24,881	24,931	25,092	25,336	25,507	25,799	25,971	26,209	26,455	26,753	27,031	27,211	27,478
APS	8,980	9,231	9,465	9,553	9,592	9,643	9,689	9,748	9,819	9,876	9,938	10,000	10,076	10,145	10,197	10,273
ATSI	10,833	10,921	11,021	11,091	11,055	11,073	11,108	11,160	11,216	11,266	11,308	11,357	11,404	11,461	11,513	11,562
COMED	16,027	16,266	16,486	16,683	16,642	16,697	16,803	16,937	17,089	17,244	17,372	17,500	17,663	17,802	17,995	18,136
DAYTON	2,961	3,010	3,065	3,096	3,080	3,085	3,105	3,127	3,152	3,170	3,195	3,214	3,242	3,269	3,292	3,309
DEOK	4,660	4,720	4,784	4,807	4,793	4,853	4,923	4,918	4,957	4,960	5,003	5,073	5,143	5,157	5,161	5,202
DLCO	2,202	2,222	2,240	2,250	2,238	2,235	2,237	2,246	2,252	2,252	2,260	2,269	2,278	2,288	2,299	2,301
EKPC	2,916	2,946	2,984	3,003	3,020	3,041	3,060	3,079	3,101	3,127	3,151	3,174	3,196	3,218	3,242	3,273
DIVERSITY - WESTERN(-)	1,083	922	976	1,003	1,095	1,228	1,088	1,099	1,090	1,293	1,349	1,372	1,199	1,137	1,259	1,478
PJM WESTERN	71,335	72,625	73,770	74,361	74,256	74,491	75,173	75,623	76,295	76,573	77,087	77,670	78,556	79,234	79,651	80,056
DOM	18,509	19,128	19,673	20,058	20,204	20,365	20,584	20,820	21,050	21,277	21,498	21,736	21,972	22,222	22,433	22,664
DIVERSITY - INTERREGIONAL(-)	371	748	785	816	730	541	803	766	854	560	466	420	852	870	821	555
PJM RTO	136,847	139,147	141,353	142,512	142,477	142,972	143,775	144,660	145,691	146,519	147,527	148,575	149,722	150,872	151,781	152,807

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.
Winter season indicates peak from December, January, February.

Table E-1

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION 2016 - 2026

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Annual Growth Rate (10 yr)
AE	10,399	10,407	10,441	10,441	10,387	10,328	10,315	10,309	10,340	10,303	10,282	(0.1%)
		0.1%	0.3%	0.0%	-0.5%	-0.6%	-0.1%	-0.1%	0.3%	-0.4%	-0.2%	
BGE	34,075	34,236	34,461	34,568	34,640	34,644	34,789	34,934	35,200	35,259	35,402	0.4%
		0.5%	0.7%	0.3%	0.2%	0.0%	0.4%	0.4%	0.8%	0.2%	0.4%	
DPL	19,108	19,277	19,439	19,519	19,561	19,551	19,608	19,671	19,816	19,846	19,918	0.4%
		0.9%	0.8%	0.4%	0.2%	-0.1%	0.3%	0.3%	0.7%	0.2%	0.4%	
JCPL	22,880	23,151	23,437	23,531	23,383	23,260	23,288	23,337	23,471	23,453	23,491	0.3%
		1.2%	1.2%	0.4%	-0.6%	-0.5%	0.1%	0.2%	0.6%	-0.1%	0.2%	
METED	16,014	16,245	16,483	16,607	16,610	16,617	16,729	16,842	17,028	17,113	17,259	0.8%
		1.4%	1.5%	0.8%	0.0%	0.0%	0.7%	0.7%	1.1%	0.5%	0.9%	
PECO	41,882	42,434	42,989	43,274	43,236	43,211	43,435	43,692	44,121	44,290	44,585	0.6%
		1.3%	1.3%	0.7%	-0.1%	-0.1%	0.5%	0.6%	1.0%	0.4%	0.7%	
PENLC	18,062	18,049	18,082	18,065	18,129	18,079	18,086	18,071	18,118	18,089	18,116	0.0%
		-0.1%	0.2%	-0.1%	0.4%	-0.3%	0.0%	-0.1%	0.3%	-0.2%	0.1%	
PEPCO	32,057	32,242	32,501	32,644	32,759	32,751	32,879	33,016	33,282	33,357	33,520	0.4%
		0.6%	0.8%	0.4%	0.4%	-0.0%	0.4%	0.4%	0.8%	0.2%	0.5%	
PL	41,380	41,835	42,339	42,563	42,583	42,526	42,710	42,905	43,282	43,400	43,680	0.5%
		1.1%	1.2%	0.5%	0.0%	-0.1%	0.4%	0.5%	0.9%	0.3%	0.6%	
PS	45,085	45,430	45,811	45,934	45,880	45,678	45,734	45,772	45,953	45,922	45,997	0.2%
		0.8%	0.8%	0.3%	-0.1%	-0.4%	0.1%	0.1%	0.4%	-0.1%	0.2%	
RECO	1,535	1,537	1,542	1,541	1,546	1,539	1,538	1,537	1,541	1,539	1,536	0.0%
		0.1%	0.3%	-0.1%	0.3%	-0.5%	-0.1%	-0.1%	0.3%	-0.1%	-0.2%	
UGI	1,036	1,046	1,056	1,058	1,048	1,042	1,042	1,042	1,045	1,041	1,044	0.1%
		1.0%	1.0%	0.2%	-0.9%	-0.6%	0.0%	0.0%	0.3%	-0.4%	0.3%	
PJM MID-ATLANTIC	283,513	285,889	288,581	289,745	289,762	289,226	290,153	291,128	293,197	293,612	294,830	0.4%
		0.8%	0.9%	0.4%	0.0%	-0.2%	0.3%	0.3%	0.7%	0.1%	0.4%	
FE-EAST	56,956	57,445	58,002	58,203	58,122	57,956	58,103	58,250	58,617	58,655	58,866	0.3%
		0.9%	1.0%	0.3%	-0.1%	-0.3%	0.3%	0.3%	0.6%	0.1%	0.4%	
PLGRP	42,416	42,881	43,395	43,621	43,631	43,568	43,752	43,947	44,327	44,441	44,724	0.5%
		1.1%	1.2%	0.5%	0.0%	-0.1%	0.4%	0.4%	0.9%	0.3%	0.6%	

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation.
All average growth rates are calculated from the first year of the forecast (2016).

Table E-1 (Continued)

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION 2027 - 2031

	2027	2028	2029	2030	2031	Annual Growth Rate (15 yr)
AE	10,260	10,267	10,224	10,175	10,145	(0.2%)
	-0.2%	0.1%	-0.4%	-0.5%	-0.3%	
BGE	35,552	35,826	35,908	36,003	36,131	0.4%
	0.4%	0.8%	0.2%	0.3%	0.4%	
DPL	20,002	20,155	20,185	20,205	20,219	0.4%
	0.4%	0.8%	0.1%	0.1%	0.1%	
JCPL	23,558	23,700	23,736	23,733	23,800	0.3%
	0.3%	0.6%	0.2%	-0.0%	0.3%	
METED	17,428	17,643	17,794	17,916	18,089	0.8%
	1.0%	1.2%	0.9%	0.7%	1.0%	
PECO	44,946	45,444	45,765	46,049	46,426	0.7%
	0.8%	1.1%	0.7%	0.6%	0.8%	
PENLC	18,135	18,184	18,157	18,142	18,183	0.0%
	0.1%	0.3%	-0.1%	-0.1%	0.2%	
PEPCO	33,690	33,955	34,053	34,172	34,306	0.5%
	0.5%	0.8%	0.3%	0.3%	0.4%	
PL	43,996	44,439	44,705	44,911	45,230	0.6%
	0.7%	1.0%	0.6%	0.5%	0.7%	
PS	46,072	46,278	46,255	46,209	46,314	0.2%
	0.2%	0.4%	-0.0%	-0.1%	0.2%	
RECO	1,534	1,536	1,529	1,525	1,525	(0.0%)
	-0.1%	0.1%	-0.5%	-0.3%	0.0%	
UGI	1,045	1,052	1,054	1,055	1,056	0.1%
	0.1%	0.7%	0.2%	0.1%	0.1%	
PJM MID-ATLANTIC	296,218	298,479	299,365	300,095	301,424	0.4%
	0.5%	0.8%	0.3%	0.2%	0.4%	
FE-EAST	59,121	59,527	59,687	59,791	60,072	0.4%
	0.4%	0.7%	0.3%	0.2%	0.5%	
PLGRP	45,041	45,491	45,759	45,966	46,286	0.6%
	0.7%	1.0%	0.6%	0.5%	0.7%	

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation.
All average growth rates are calculated from the first year of the forecast (2016).

Table E-1

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO 2016 - 2026

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Annual Growth Rate (10 yr)
AEP	135,818	137,602	139,637	140,845	141,547	142,048	143,277	144,480	146,270	147,150	148,455	0.9%
		1.3%	1.5%	0.9%	0.5%	0.4%	0.9%	0.8%	1.2%	0.6%	0.9%	
APS	50,320	51,404	52,246	52,779	53,017	53,149	53,545	53,984	54,574	54,864	55,248	0.9%
		2.2%	1.6%	1.0%	0.5%	0.2%	0.7%	0.8%	1.1%	0.5%	0.7%	
ATSI	69,542	69,950	70,515	70,781	71,065	71,088	71,430	71,701	72,189	72,398	72,791	0.5%
		0.6%	0.8%	0.4%	0.4%	0.0%	0.5%	0.4%	0.7%	0.3%	0.5%	
COMED	102,549	103,923	105,470	106,426	106,868	107,220	108,178	109,139	110,522	111,347	112,470	0.9%
		1.3%	1.5%	0.9%	0.4%	0.3%	0.9%	0.9%	1.3%	0.7%	1.0%	
DAYTON	17,923	18,195	18,511	18,681	18,673	18,704	18,851	18,996	19,213	19,330	19,495	0.8%
		1.5%	1.7%	0.9%	-0.0%	0.2%	0.8%	0.8%	1.1%	0.6%	0.9%	
DEOK	27,894	28,224	28,616	28,859	28,993	29,080	29,321	29,555	29,891	30,067	30,325	0.8%
		1.2%	1.4%	0.8%	0.5%	0.3%	0.8%	0.8%	1.1%	0.6%	0.9%	
DLCO	14,790	14,899	15,024	15,075	15,092	15,064	15,107	15,150	15,241	15,264	15,344	0.4%
		0.7%	0.8%	0.3%	0.1%	-0.2%	0.3%	0.3%	0.6%	0.2%	0.5%	
EKPC	10,904	10,950	11,024	11,062	11,127	11,156	11,206	11,254	11,336	11,352	11,402	0.4%
		0.4%	0.7%	0.3%	0.6%	0.3%	0.4%	0.4%	0.7%	0.1%	0.4%	
PJM WESTERN	429,740	435,147	441,043	444,508	446,382	447,509	450,915	454,259	459,236	461,772	465,530	0.8%
		1.3%	1.4%	0.8%	0.4%	0.3%	0.8%	0.7%	1.1%	0.6%	0.8%	
DOM	98,082	100,776	103,471	105,239	105,845	106,527	107,641	108,827	110,405	111,352	112,503	1.4%
		2.7%	2.7%	1.7%	0.6%	0.6%	1.0%	1.1%	1.5%	0.9%	1.0%	
PJM RTO	811,335	821,812	833,095	839,492	841,989	843,262	848,709	854,214	862,838	866,736	872,863	0.7%
		1.3%	1.4%	0.8%	0.3%	0.2%	0.6%	0.6%	1.0%	0.5%	0.7%	

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation.
All average growth rates are calculated from the first year of the forecast (2016).

Table E-1 (Continued)

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO 2027 - 2031

	2027	2028	2029	2030	2031	Annual Growth Rate (15 yr)
AEP	149,863	151,812	153,102	154,347	155,849	0.9%
	0.9%	1.3%	0.8%	0.8%	1.0%	
APS	55,721	56,356	56,715	57,104	57,520	0.9%
	0.9%	1.1%	0.6%	0.7%	0.7%	
ATSI	73,214	73,788	74,076	74,332	74,788	0.5%
	0.6%	0.8%	0.4%	0.3%	0.6%	
COMED	113,669	115,173	116,264	117,188	118,373	1.0%
	1.1%	1.3%	0.9%	0.8%	1.0%	
DAYTON	19,678	19,922	20,090	20,216	20,398	0.9%
	0.9%	1.2%	0.8%	0.6%	0.9%	
DEOK	30,610	31,001	31,261	31,497	31,788	0.9%
	0.9%	1.3%	0.8%	0.8%	0.9%	
DLCO	15,426	15,552	15,602	15,650	15,733	0.4%
	0.5%	0.8%	0.3%	0.3%	0.5%	
EKPC	11,451	11,541	11,565	11,608	11,666	0.5%
	0.4%	0.8%	0.2%	0.4%	0.5%	
PJM WESTERN	469,632	475,145	478,675	481,942	486,115	0.8%
	0.9%	1.2%	0.7%	0.7%	0.9%	
DOM	113,755	115,405	116,556	117,562	118,629	1.3%
	1.1%	1.5%	1.0%	0.9%	0.9%	
PJM RTO	879,605	889,029	894,596	899,599	906,168	0.7%
	0.8%	1.1%	0.6%	0.6%	0.7%	

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation.
All average growth rates are calculated from the first year of the forecast (2016).

Table E-2

**MONTHLY NET ENERGY FORECAST (GWh) FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION**

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	PJM MID-ATLANTIC
Jan 2016	872	3,141	1,767	1,956	1,452	3,665	1,648	2,850	3,944	3,788	124	102	25,309
Feb 2016	801	2,865	1,626	1,803	1,356	3,394	1,544	2,615	3,637	3,519	116	94	23,370
Mar 2016	798	2,750	1,531	1,783	1,333	3,355	1,535	2,548	3,527	3,527	118	91	22,896
Apr 2016	726	2,437	1,343	1,630	1,207	3,057	1,405	2,299	3,115	3,291	112	78	20,700
May 2016	770	2,490	1,385	1,694	1,231	3,130	1,428	2,396	3,124	3,424	119	76	21,267
Jun 2016	933	2,992	1,655	2,055	1,339	3,689	1,444	2,893	3,308	4,055	140	80	24,583
Jul 2016	1,148	3,367	1,908	2,439	1,466	4,186	1,537	3,237	3,624	4,632	161	89	27,794
Aug 2016	1,099	3,285	1,853	2,323	1,458	4,065	1,559	3,174	3,615	4,506	156	87	27,180
Sep 2016	843	2,632	1,489	1,809	1,227	3,315	1,412	2,584	3,121	3,650	127	75	22,284
Oct 2016	778	2,502	1,399	1,717	1,245	3,191	1,458	2,368	3,196	3,489	122	79	21,544
Nov 2016	767	2,591	1,444	1,716	1,266	3,217	1,466	2,417	3,326	3,417	116	85	21,828
Dec 2016	864	3,023	1,708	1,955	1,434	3,618	1,626	2,676	3,843	3,787	124	100	24,758

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	MID-ATLANTIC
Jan 2017	878	3,184	1,801	1,997	1,487	3,747	1,662	2,895	4,029	3,852	125	104	25,761
Feb 2017	776	2,791	1,590	1,766	1,333	3,329	1,495	2,549	3,561	3,433	112	92	22,827
Mar 2017	801	2,773	1,552	1,813	1,360	3,412	1,541	2,573	3,584	3,572	118	92	23,191
Apr 2017	727	2,451	1,357	1,650	1,222	3,100	1,399	2,317	3,145	3,320	113	79	20,880
May 2017	772	2,508	1,400	1,719	1,254	3,182	1,434	2,420	3,173	3,461	119	77	21,519
Jun 2017	936	3,013	1,674	2,086	1,363	3,754	1,448	2,919	3,355	4,099	141	80	24,868
Jul 2017	1,151	3,383	1,924	2,468	1,486	4,245	1,536	3,259	3,663	4,671	161	90	28,037
Aug 2017	1,103	3,307	1,873	2,356	1,484	4,131	1,565	3,204	3,666	4,556	157	88	27,490
Sep 2017	845	2,647	1,502	1,831	1,246	3,359	1,412	2,603	3,157	3,677	127	76	22,482
Oct 2017	781	2,523	1,416	1,745	1,269	3,244	1,465	2,394	3,249	3,527	123	81	21,817
Nov 2017	771	2,615	1,463	1,745	1,290	3,271	1,473	2,443	3,377	3,458	117	87	22,110
Dec 2017	866	3,041	1,725	1,975	1,451	3,660	1,619	2,666	3,876	3,804	124	100	24,907

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	MID-ATLANTIC
Jan 2018	883	3,219	1,825	2,032	1,520	3,815	1,674	2,936	4,098	3,907	126	106	26,141
Feb 2018	780	2,813	1,608	1,792	1,356	3,380	1,499	2,576	3,611	3,470	113	92	23,090
Mar 2018	802	2,787	1,564	1,832	1,374	3,449	1,535	2,588	3,613	3,595	118	93	23,350
Apr 2018	731	2,472	1,371	1,680	1,248	3,155	1,412	2,343	3,206	3,362	113	80	21,173
May 2018	775	2,524	1,412	1,744	1,274	3,226	1,437	2,441	3,216	3,496	120	78	21,743
Jun 2018	938	3,026	1,684	2,108	1,378	3,794	1,446	2,939	3,383	4,129	141	81	25,047
Jul 2018	1,156	3,412	1,940	2,500	1,516	4,315	1,549	3,299	3,727	4,728	163	91	28,396
Aug 2018	1,106	3,322	1,885	2,381	1,501	4,179	1,564	3,228	3,701	4,589	157	89	27,702
Sep 2018	846	2,660	1,509	1,850	1,260	3,392	1,412	2,617	3,186	3,696	127	77	22,632
Oct 2018	783	2,537	1,427	1,764	1,289	3,281	1,472	2,416	3,288	3,554	123	81	22,015
Nov 2018	773	2,630	1,474	1,763	1,307	3,308	1,476	2,462	3,410	3,484	118	87	22,292
Dec 2018	868	3,059	1,740	1,991	1,460	3,695	1,606	2,656	3,900	3,801	123	101	25,000

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation.

Table E-2

MONTHLY NET ENERGY FORECAST (GWh) FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	PJM WESTERN	DOM	PJM RTO
Jan 2016	12,706	4,787	6,188	8,879	1,606	2,482	1,274	1,202	39,124	9,018	73,451
Feb 2016	11,646	4,402	5,787	8,212	1,479	2,270	1,183	1,043	36,022	8,193	67,585
Mar 2016	11,370	4,285	5,792	8,207	1,459	2,215	1,195	922	35,445	7,774	66,115
Apr 2016	10,170	3,766	5,339	7,634	1,340	2,025	1,117	740	32,131	6,929	59,760
May 2016	10,445	3,816	5,481	7,886	1,387	2,111	1,158	734	33,018	7,223	61,508
Jun 2016	11,179	4,108	5,792	8,823	1,525	2,486	1,293	858	36,064	8,708	69,355
Jul 2016	12,031	4,438	6,263	10,053	1,661	2,712	1,415	935	39,508	9,644	76,946
Aug 2016	12,064	4,433	6,275	9,902	1,675	2,721	1,400	941	39,411	9,425	76,016
Sep 2016	10,380	3,780	5,453	8,006	1,397	2,179	1,168	756	33,119	7,789	63,192
Oct 2016	10,589	3,866	5,553	8,066	1,414	2,131	1,169	756	33,544	7,212	62,300
Nov 2016	10,861	4,038	5,520	7,962	1,406	2,132	1,156	888	33,963	7,473	63,264
Dec 2016	12,377	4,601	6,099	8,919	1,574	2,430	1,262	1,129	38,391	8,694	71,843

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	WESTERN	DOM	PJM RTO
Jan 2017	13,006	4,933	6,282	9,067	1,647	2,533	1,294	1,216	39,978	9,322	75,061
Feb 2017	11,430	4,354	5,634	8,061	1,451	2,221	1,154	1,018	35,323	8,158	66,308
Mar 2017	11,579	4,399	5,853	8,368	1,487	2,252	1,210	929	36,077	8,036	67,304
Apr 2017	10,308	3,854	5,367	7,733	1,361	2,052	1,126	743	32,544	7,152	60,576
May 2017	10,619	3,918	5,537	8,029	1,415	2,144	1,170	739	33,571	7,464	62,554
Jun 2017	11,349	4,205	5,844	8,958	1,551	2,521	1,306	863	36,597	8,958	70,423
Jul 2017	12,174	4,529	6,293	10,184	1,683	2,742	1,425	940	39,970	9,888	77,895
Aug 2017	12,247	4,536	6,337	10,067	1,705	2,759	1,416	947	40,014	9,681	77,185
Sep 2017	10,525	3,869	5,493	8,124	1,421	2,207	1,179	758	33,576	8,018	64,076
Oct 2017	10,784	3,976	5,618	8,209	1,444	2,167	1,182	762	34,142	7,455	63,414
Nov 2017	11,054	4,146	5,579	8,103	1,437	2,168	1,169	896	34,552	7,719	64,381
Dec 2017	12,527	4,685	6,113	9,020	1,593	2,458	1,268	1,139	38,803	8,925	72,635

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	WESTERN	DOM	PJM RTO
Jan 2018	13,269	5,037	6,370	9,256	1,686	2,583	1,311	1,229	40,741	9,615	76,497
Feb 2018	11,624	4,435	5,691	8,198	1,481	2,257	1,166	1,028	35,880	8,396	67,366
Mar 2018	11,707	4,463	5,874	8,463	1,508	2,274	1,215	934	36,438	8,263	68,051
Apr 2018	10,506	3,938	5,441	7,895	1,395	2,089	1,140	749	33,153	7,381	61,707
May 2018	10,780	3,986	5,588	8,163	1,442	2,176	1,182	742	34,059	7,684	63,486
Jun 2018	11,493	4,260	5,873	9,074	1,573	2,548	1,315	867	37,003	9,179	71,229
Jul 2018	12,403	4,616	6,390	10,380	1,721	2,788	1,445	948	40,691	10,140	79,227
Aug 2018	12,394	4,598	6,378	10,196	1,728	2,792	1,426	951	40,463	9,900	78,065
Sep 2018	10,647	3,924	5,525	8,226	1,441	2,233	1,186	761	33,943	8,208	64,783
Oct 2018	10,934	4,044	5,671	8,334	1,469	2,196	1,191	766	34,605	7,654	64,274
Nov 2018	11,198	4,208	5,621	8,213	1,459	2,195	1,178	903	34,975	7,913	65,180
Dec 2018	12,682	4,737	6,093	9,072	1,608	2,485	1,269	1,146	39,092	9,138	73,230

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation.

Table E-3

MONTHLY NET ENERGY FORECAST (GWh) FOR FE-EAST AND PLGRP

	FE_EAST	PLGRP
Jan 2016	5,056	4,046
Feb 2016	4,703	3,731
Mar 2016	4,651	3,618
Apr 2016	4,242	3,193
May 2016	4,353	3,200
Jun 2016	4,838	3,388
Jul 2016	5,442	3,713
Aug 2016	5,340	3,702
Sep 2016	4,448	3,196
Oct 2016	4,420	3,275
Nov 2016	4,448	3,411
Dec 2016	5,015	3,943

	FE_EAST	PLGRP
Jan 2017	5,146	4,133
Feb 2017	4,594	3,653
Mar 2017	4,714	3,676
Apr 2017	4,271	3,224
May 2017	4,407	3,250
Jun 2017	4,897	3,435
Jul 2017	5,490	3,753
Aug 2017	5,405	3,754
Sep 2017	4,489	3,233
Oct 2017	4,479	3,330
Nov 2017	4,508	3,464
Dec 2017	5,045	3,976

	FE_EAST	PLGRP
Jan 2018	5,226	4,204
Feb 2018	4,647	3,703
Mar 2018	4,741	3,706
Apr 2018	4,340	3,286
May 2018	4,455	3,294
Jun 2018	4,932	3,464
Jul 2018	5,565	3,818
Aug 2018	5,446	3,790
Sep 2018	4,522	3,263
Oct 2018	4,525	3,369
Nov 2018	4,546	3,497
Dec 2018	5,057	4,001

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation.

Table F-1

PJM RTO HISTORICAL PEAKS
(MW)

SUMMER

YEAR	NORMALIZED BASE	NORMALIZED COOLING	NORMALIZED TOTAL	UNRESTRICTED PEAK	PEAK DATE	TIME
1998				133,189	Tuesday, July 21, 1998	17:00
1999	89,051			141,321	Friday, July 30, 1999	17:00
2000	91,069	47,601	138,670	131,803	Wednesday, August 9, 2000	17:00
2001	92,113	50,072	142,185	150,929	Thursday, August 9, 2001	16:00
2002	92,690	54,195	146,885	150,830	Thursday, August 1, 2002	17:00
2003	93,653	52,902	146,555	145,233	Thursday, August 21, 2003	17:00
2004	95,169	53,091	148,260	139,219	Tuesday, August 3, 2004	17:00
2005	95,786	58,994	154,780	155,209	Tuesday, July 26, 2005	16:00
2006	95,253	62,147	157,400	166,866	Wednesday, August 2, 2006	17:00
2007	96,680	62,975	159,655	161,988	Wednesday, August 8, 2007	16:00
2008	97,144	62,426	159,570	150,560	Monday, June 9, 2008	17:00
2009	94,670	57,120	151,790	145,056	Monday, August 10, 2009	16:00
2010	93,133	61,112	154,245	157,188	Wednesday, July 7, 2010	17:00
2011	93,328	60,032	153,360	165,466	Thursday, July 21, 2011	17:00
2012	92,948	60,997	153,945	158,151	Tuesday, July 17, 2012	17:00
2013	92,464	56,936	149,400	159,039	Thursday, July 18, 2013	17:00
2014	91,837	58,268	150,105	141,402	Tuesday, June 17, 2014	18:00
2015	91,108	59,187	150,295	143,497	Tuesday, July 28, 2015	17:00

WINTER

YEAR	NORMALIZED BASE	NORMALIZED HEATING	NORMALIZED TOTAL	UNRESTRICTED PEAK	PEAK DATE	TIME
97/98				103,235	Wednesday, January 14, 1998	19:00
98/99	87,537			116,078	Tuesday, January 5, 1999	19:00
99/00	89,288	26,292	115,580	118,438	Thursday, January 27, 2000	20:00
00/01	91,324	26,416	117,740	118,051	Wednesday, December 20, 2000	19:00
01/02	92,410	23,610	116,020	112,221	Wednesday, January 2, 2002	19:00
02/03	92,591	27,879	120,470	129,972	Thursday, January 23, 2003	19:00
03/04	93,710	28,970	122,680	122,357	Friday, January 23, 2004	9:00
04/05	94,387	30,003	124,390	131,164	Monday, December 20, 2004	19:00
05/06	94,643	32,257	126,900	126,703	Wednesday, December 14, 2005	19:00
06/07	96,076	34,004	130,080	136,739	Monday, February 5, 2007	20:00
07/08	97,180	34,870	132,050	128,313	Wednesday, January 2, 2008	19:00
08/09	96,326	32,774	129,100	134,021	Friday, January 16, 2009	19:00
09/10	93,425	34,945	128,370	125,276	Monday, January 4, 2010	19:00
10/11	91,823	36,977	128,800	132,228	Tuesday, December 14, 2010	19:00
11/12	92,284	34,056	126,340	124,420	Tuesday, January 3, 2012	19:00
12/13	92,061	33,919	125,980	128,724	Tuesday, January 22, 2013	19:00
13/14	91,120	38,020	129,140	141,746	Tuesday, January 7, 2014	19:00
14/15	90,162	38,108	128,270	142,762	Friday, February 20, 2015	8:00

Notes:
Normalized values for 2005 - 2015 are calculated by PJM staff using a methodology described in Manual 19.
Normalized base values are calculated by PJM staff using a two-period average of peak loads on non-heating/non-coolong days.
All times are shown in hour ending Eastern Prevailing Time and historic peak values reflect current membership of the PJM RTO.

Table F-2

PJM RTO HISTORICAL NET ENERGY
(GWH)

YEAR	ENERGY	GROWTH RATE
1998	718,551	0.0%
1999	740,052	3.0%
2000	756,237	2.2%
2001	754,541	-0.2%
2002	782,300	3.7%
2003	780,693	-0.2%
2004	796,257	2.0%
2005	822,873	3.3%
2006	802,509	-2.5%
2007	835,782	4.1%
2008	822,098	-1.6%
2009	780,693	-5.0%
2010	819,576	5.0%
2011	805,366	-1.7%
2012	791,219	-1.8%
2013	794,484	0.4%
2014	795,519	0.1%

Note: All historic net energy values reflect the current membership of the PJM RTO.

Table G-1

ANNUALIZED AVERAGE GROWTH OF INDEXED ECONOMIC VARIABLE FOR EACH PJM ZONE AND RTO

	5-Year (2016-21)	10-Year (2016-26)	15-Year (2016-31)
AE	0.8%	0.7%	0.7%
BGE	1.3%	1.2%	1.2%
DPL	1.6%	1.4%	1.3%
JCPL	1.2%	1.0%	1.0%
METED	1.7%	1.5%	1.5%
PECO	1.6%	1.4%	1.4%
PENLC	1.2%	1.1%	1.0%
PEPCO	1.6%	1.4%	1.3%
PL	1.6%	1.4%	1.3%
PS	1.2%	1.0%	1.0%
RECO	1.1%	0.9%	0.9%
UGI	1.0%	0.8%	0.7%
AEP	1.8%	1.6%	1.5%
APS	1.8%	1.6%	1.5%
ATSI	1.5%	1.3%	1.2%
COMED	1.6%	1.4%	1.3%
DAYTON	1.3%	1.1%	1.0%
DEOK	1.7%	1.5%	1.4%
DLCO	1.4%	1.2%	1.2%
EKPC	1.8%	1.6%	1.5%
DOM	1.7%	1.5%	1.4%
PJM RTO	1.6%	1.4%	1.3%

Source: Moody's Analytics, October, 2015

Notes:
Values presented are annualized compound average growth rates.
Indexed economic variable is a combination of U.S. Gross Domestic Product, Gross Metropolitan Product, Real Personal Income, Population, Households, and Non-Manufacturing Employment.