Net Revenue

The Market Monitoring Unit (MMU) analyzed measures of PJM Energy Market structure, participant conduct and market performance. As part of the review of market performance, the MMU analyzed the net revenues earned by combustion turbines (CT), combined cycle (CC), and coal plant (CP) generating units.

Overview

Net Revenue

- **Net Revenue Adequacy.** Net revenue is the contribution to total fixed costs received by generators from PJM Energy, Capacity and Ancillary Service Markets and from the provision of black start and reactive services. Net revenue is the amount that remains, after short run variable costs have been subtracted from gross revenue, to cover total fixed costs which include a return on investment, depreciation, taxes and fixed operation and maintenance expenses.

  The adequacy of net revenue can be assessed both by comparing net revenue to total fixed costs and by comparing net revenue to avoidable costs. The comparison of net revenue to total fixed costs is an indicator of the incentive to invest in new and existing units. The comparison of net revenue to avoidable costs for both hypothetical new entrant units and for existing units is an indicator of the extent to which the revenues from PJM markets provide sufficient incentive for continued operations in PJM Markets.

- **Net Revenue and Total Fixed Costs.** When compared to total fixed costs, net revenue is an indicator of generation investment profitability and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation and in existing generation to serve PJM markets. Net revenue is the contribution to total fixed costs received by generators from all PJM markets. Although it can be expected that in the long run, in a competitive market, net revenue from all sources will cover the total fixed costs of investing in new generating resources, including a competitive return on investment, when there is a market based need, actual results are expected to vary from year to year. Wholesale energy markets, like other markets, are cyclical. When the markets are long, prices will be lower and when the markets are short, prices will be higher.

  Net revenues are significantly affected by fuel prices, energy prices and capacity prices. Gas prices decreased on average by 10 percent and coal prices increased on average by 19 percent in 2011. The combination of lower energy prices, lower gas prices and higher coal prices resulted in higher energy revenues for the new entrant CT and CC unit in most zones and lower energy net revenues for the new entrant coal unit in all zones in 2011. However, revenue from the capacity market was lower in 2011, which affected total net revenues for all units. Total new entrant CT net revenue decreased in 2011 in all but five zones. Total new entrant CC net revenue increased in all but five zones. Total new entrant coal unit net revenue was lower in all zones except AEP.

- **Actual Net Revenue and Avoidable Costs.** Avoidable costs are the costs which must be paid each year in order to keep a unit operating. Avoidable costs are less than total fixed costs, which include the return on and of capital, and more than marginal costs, which are the short run incremental costs of producing energy. It is rational for an owner to continue to operate a unit if it is covering its avoidable costs and therefore contributing to covering fixed costs. It is not rational for an owner to continue to operate a unit if it is not covering and not expected to cover its avoidable costs. As a general matter, under those conditions, retirement of the unit is the logical option. The analysis, which compares net revenues to avoidable costs, is a measure of the extent to which units in PJM may be at risk of retirement.

  It is not rational for an owner to invest in environmental controls if a unit is not covering and is not expected to cover its avoidable costs plus the annualized fixed costs of the investment. As a general matter, under those conditions, retirement of the unit is the logical option. The analysis, which compares net revenues to avoidable costs plus the annualized fixed costs of investments in environmental controls where relevant, is a measure of the extent to which such units in PJM may be at risk of retirement.

For both the CT and CC technologies, as well as for the gas-fired and oil-fired steam technologies, RPM revenue has provided a required supplemental revenue stream to incent continued operations in PJM for units that do not recover 100 percent of fixed costs through energy market revenue. Nuclear and run of river hydro technologies generally recover avoidable costs entirely from the energy market.

The coal plant technologies have higher avoidable costs and are more dependent on energy market net revenues than the CT and CC technologies. The total installed capacity of sub-critical coal and supercritical coal units that did not cover avoidable costs from energy revenues plus capacity revenues in 2011 was 5,642 MW. Generally, coal units that did not recover avoidable costs tended to be smaller and less efficient, facing higher operating costs and higher avoidable costs.

Other coal plants received significant energy market revenues but had made project investments associated with maintaining or improving reliability or environmental regulations, in which case, failure to cover avoidable costs, as defined in RPM, may be only a failure to recover the annual project recovery rate. If project costs are sunk, or if the project life is longer than the PJM defined recovery period for the calculation of the avoidable cost rate, it is rational to bid units below avoidable costs, as defined in RPM. In either case, these units may be at a lower risk of retirement than units not recovering avoidable costs excluding capital recovery, as they may stay in service for the duration of the project life.

Coal plants also face a higher risk of capital expenditures to comply with environmental regulations. The total installed capacity of sub-critical coal and supercritical coal units that do not have NO_X, SO_2, or particulate controls in place is 17,104 MW. Of the capacity lacking NO_X, SO_2, or particulate controls, 83 percent is associated with plants older than 40 years.

Conclusion

Wholesale electric power markets are affected by externally imposed reliability requirements. A regulatory authority external to the market makes a determination as to the acceptable level of reliability which is enforced through a requirement to maintain a target level of installed or unforced capacity. The requirement to maintain a target level of installed capacity can be enforced via a variety of mechanisms, including government construction of generation, full-requirement contracts with developers to construct and operate generation, state utility commission mandates to construct capacity, or capacity markets of various types. Regardless of the enforcement mechanism, the exogenous requirement to construct capacity in excess of what is constructed in response to energy market signals has an impact on energy markets. The reliability requirement results in maintaining a level of capacity in excess of the level that would result from the operation of an energy market alone. The result of that additional capacity is to reduce the level and volatility of energy market prices and to reduce the duration of high energy market prices. This, in turn, reduces net revenue to generation owners which reduces the incentive to invest. The exact level of both aggregate and locational excess capacity is a function of the calculation methods used by RTOs and ISOs.

A capacity market is a formal mechanism, with both administrative and market-based components, used to allocate the costs of maintaining the level of capacity required to maintain the reliability target. A capacity market is an explicit mechanism for valuing capacity and is preferable to nonmarket and nontransparent mechanisms for that reason.

The historical level of net revenues in PJM markets was not the result of the $1,000-per-MWh offer cap, of local market power mitigation, or of a basic incompatibility between wholesale electricity markets and competition. Competitive markets can, and do, signal scarcity and surplus conditions through market clearing prices. Nonetheless, in PJM as in other wholesale electric power markets, the application of reliability standards means that scarcity conditions in the Energy Market occur with reduced frequency. Traditional levels of reliability require units that are only directly used and priced under relatively unusual load conditions. Thus, the Energy Market alone frequently does not directly compensate the resources needed to provide for reliability.

PJM's RPM is an explicit effort to address these issues. RPM is a capacity market design intended to send supplemental signals to the market based on the locational and forward-looking need for generation resources to maintain system reliability in the context of a long-run competitive equilibrium in the Energy Market. The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability.

The net revenue results illustrate some fundamentals of the PJM wholesale power market. CTs are generally the highest incremental cost units and therefore tend to be marginal in the energy market and set prices when they run. When this occurs, CT energy market net revenues tend to be low and there is little contribution to fixed costs. High demand hours result in less efficient CTs setting prices, which results in higher net revenues for more efficient CTs and other inframarginal units.

The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. In the PJM design, the capacity market provides a significant stream of revenue that contributes to the recovery of total costs for new and existing peaking units that may be needed for reliability during years in which energy net revenues are not sufficient. The capacity market is also a significant source of net revenue to cover the fixed costs of investing in new intermediate and base load units, although capacity revenues are a larger part of net revenue for peaking units. However, when the actual fixed costs of capacity increase rapidly, or, when the energy net revenues used as the offset in determining capacity market prices are higher than actual energy net revenues, there is a corresponding lag in capacity market prices which will tend to lead to an under recovery of the fixed costs of CTs. The reverse can also happen, leading to an over recovery of the fixed costs of CTs, although it has happened less frequently in PJM markets.

Net Revenue

Net revenue is an indicator of generation investment profitability, and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation to serve PJM markets. Net revenue equals total revenue received by generators from PJM Energy, Capacity and Ancillary Service Markets and from the provision of black start and reactive services less the variable costs of energy production. In other words, net revenue is the amount that remains, after short run variable costs of energy production have been subtracted from gross revenue, to cover fixed costs, which include a return on investment, depreciation, taxes and fixed operation and maintenance expenses.

In a perfectly competitive, energy-only market in long-run equilibrium, net revenue from the energy market would be expected to equal the total of all annualized fixed costs for the marginal unit, including a competitive return on investment. The PJM market design includes other markets intended to contribute to the payment of fixed costs. In PJM, the Energy, Capacity and Ancillary Service Markets are all significant sources of revenue to cover fixed costs of generators, as are payments for the provision of black start and reactive services. Thus, in a perfectly competitive market in long-run equilibrium, with energy, capacity and ancillary service payments, net revenue from all sources would be expected to equal the annualized fixed costs of generation for the marginal unit. Net revenue is a measure of whether generators are receiving competitive returns on invested capital and of whether market prices are high enough to encourage entry of new capacity. In actual wholesale power markets, where equilibrium seldom occurs, net revenue is expected to fluctuate above and below the equilibrium level based on actual conditions in all relevant markets.

Theoretical Energy Market Net Revenue

The net revenues presented in this section are theoretical as they are based on explicitly stated assumptions about how a new unit with specific characteristics would operate under economic dispatch. The economic dispatch uses technology-specific operating constraints in the calculation of a new entrant's operations and potential net revenue in PJM markets. All technology specific, zonal net revenue calculations included in the new entrant net revenue analysis in this section are based on the economic dispatch scenario.

Analysis of Energy Market net revenues for a new entrant includes three power plant configurations: a natural gas-fired CT, a two-on-one, natural gas-fired CC and a conventional CP, single reheat steam generation plant. The CT plant consists of two GE Frame 7FA.05 CTs, equipped with full inlet air mechanical refrigeration and selective catalytic reduction (SCR) for NO_x reduction. The CC plant consists of two GE Frame 7FA.05 CTs equipped with evaporative cooling, duct burners, a heat recovery steam generator (HRSG) for each CT with steam reheat and SCR for NO_x reduction with a single steam turbine generator.[1] The coal plant is a sub-critical steam CP, equipped with selective catalytic reduction system (SCR) for NO_X control, a Flue Gas Desulphurization (FGD) system with chemical injection for SO_X and mercury control, and a bag-house for particulate control.

Net revenues for 2009, 2010 and 2011 were calculated using the most economic combination of day-ahead and real-time dispatch and more flexible scheduling than previously presented in order to more closely match the expected actual dispatch. As a result, net revenues may not match net revenue calculations from previous years.

All net revenue calculations include the hourly effect of actual hourly local ambient air temperature on plant heat rates and generator output for each of the three plant configurations.[2,3] Plant heat rates were calculated for each hour to account for the efficiency changes and corresponding cost changes resulting from ambient air temperatures.

NO_X and SO_2 emission allowance costs are included in the hourly plant dispatch cost. These costs are included in the PJM definition of marginal cost. NO_X and SO_2 emission allowance costs were obtained from actual historical daily spot cash prices.[4]

A forced outage rate for each class of plant was calculated from PJM data.[5] This class-specific outage rate was then incorporated into all revenue calculations. Each plant was also given a continuous 14 day planned annual outage in the fall season.

Ancillary service revenues for the provision of synchronized reserve service for all three plant types were set to zero. Ancillary service revenues for the provision of regulation service for both the CT and CC plant were also set to zero since these plant types typically do not provide regulation service in PJM. Additionally, no black start service capability was assumed for the reference CT plant configuration in either costs or revenues.

Ancillary service revenues for the provision of regulation were calculated for the CP plant. The regulation offer price was the sum of the calculated hourly cost to supply regulation service plus an adder of $12 per PJM market rules. This offer price was compared to the hourly clearing price in the PJM Regulation Market. If the reference CP could provide regulation more profitably than energy, the unit was assumed to provide regulation during that hour.

Generators receive revenues for the provision of reactive services based on cost-of-service filings with the United States Federal Energy Regulatory Commission (FERC). The actual reactive service payments filed with and approved by the FERC for each generator class were used to determine the reactive revenues. Reactive service revenues are based on the weighted-average reactive service rate per MW-year calculated from the data in the FERC filings. In 2011, for CTs, the calculated rate is $2,384 per installed MW-year, for CCs, the calculated rate is $3,198 per installed MW-year and for CPs, the calculated rate is $1,783 per installed MW-year.

Zonal net revenues reflect zonal fuel costs which consider a variety of locational fuel indices, actual unit consumption patterns, and zone specific delivery charges.[6] The delivered fuel cost for natural gas reflects the estimated zonal, daily delivered price of natural gas and is from published commodity daily cash prices, with a basis adjustment for transportation costs.[7] Coal delivered cost incorporates the zone specific, delivered price of coal and was developed from the published prompt-month price, adjusted for rail transportation cost.[8]

Average zonal operating costs in 2011 for a CT were $53.20 per MWh, based on a design heat rate of 10,241 Btu per kWh and a VOM rate of $7.59 per MWh. Average zonal operating costs for a CP were $36.79 per MWh, based on a design heat rate of 9,240 Btu per kWh and a VOM rate of $3.22 per MWh. Average zonal operating costs for a CC were $32.75 per MWh, based on a design heat rate of 6,914 Btu per kWh and a VOM rate of $1.25

1 The duct burner firing dispatch rate is developed using the same methodology as for the unfired dispatch rate, with adjustments to the duct burner fired heat rate and output.

2 Hourly ambient conditions supplied by Telvent DTN.

3 Heat rates provided by Pasteris Energy, Inc. No-load costs are included in the heat rate and subsequently the dispatch price since each unit type is dispatched at full load for every economic hour. Therefore, there is a single offer point and no offer curve.

4 NO_X and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.

5 Outage figures obtained from the PJM eGADS database.

6 Startup fuel burns and emission rates provided by Pasteris Energy, Inc. Startup station power consumption costs were obtained from the station service rates published quarterly by PJM and netted against the MW produced during startup at the preceding applicable hourly LMP. All starts associated with combined cycle units are assumed to be hot starts.

7 Gas daily cash prices obtained from Platts.

8 Coal prompt prices obtained from Platts.

per MWh. VOM expenses include accrual of anticipated, routine major overhaul expenses.

The net revenue measure does not include the potentially significant contribution to fixed cost from the explicit or implicit sale of the option value of physical units or from bilateral agreements to sell output at a price other than the PJM Day-Ahead or Real-Time Energy Market prices, e.g., a forward price.

Capacity Market Net Revenue

Generators receive revenue from the sale of capacity in addition to revenue from the Energy and Ancillary Service Markets. In the PJM market design, the sale of capacity provides an important source of revenues to cover generator fixed costs. Capacity revenue for 2011 includes five months of the 2010/2011 RPM auction clearing price and seven months of the 2011/2012 RPM auction clearing price.[9] These capacity revenues are adjusted for the yearly, system wide forced outage rate.[10]

Table 6-1 Capacity revenue by PJM zones (Dollars per MW-year)[11]

Zone	2009	2010	2011	Average
AECO	$58,586	$61,406	$45,938	$55,310
AEP	$35,789	$48,898	$45,938	$43,542
AP	$53,440	$61,406	$45,938	$53,595
ATSI	NA	NA	NA	NA
BGE	$76,236	$67,851	$45,938	$63,342
ComEd	$35,789	$48,898	$45,938	$43,542
DAY	$35,789	$48,898	$45,938	$43,542
DLCO	$35,789	$48,898	$45,938	$43,542
Dominion	$58,586	$62,251	$46,530	$55,789
DPL	$35,789	$48,898	$45,938	$43,542
JCPL	$58,586	$61,406	$45,938	$55,310
Met-Ed	$53,440	$61,406	$45,938	$53,595
PECO	$58,586	$61,406	$45,938	$55,310
PENELEC	$53,440	$61,406	$45,938	$53,595
Pepco	$53,440	$61,406	$45,938	$53,595
PPL	$58,586	$61,406	$45,938	$55,310
PSEG	$76,236	$67,851	$45,938	$63,342
RECO	NA	NA	NA	NA
PJM	$48,385	$56,226	$45,956	$50,189

New Entrant Combustion Turbine

Energy market net revenue was calculated for a CT plant dispatched by PJM operations. For this economic dispatch scenario, it was assumed that the CT plant had a minimum run time of four hours. The unit was first committed day ahead in profitable blocks of at least four hours, including start up costs. If the unit was not already committed day ahead, it was then run in real time in stand-alone profitable blocks of at least four hours, or any hours bordering the profitable day ahead or real time block.

Table 6-2 PJM-wide net revenue for a CT under economic dispatch by market (Dollars per installed MW-year)

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
2009	$8,990	$47,188	$0	$0	$2,384	$58,563
2010	$32,781	$55,186	$0	$0	$2,384	$90,351
2011	$34,939	$45,972	$0	$0	$2,384	$83,295

Table 6-3 Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year)[12]

Zone	2009	2010	2011	Average
AECO	$11,373	$40,037	$46,157	$32,523
AEP	$3,275	$11,575	$20,839	$11,896
AP	$10,188	$32,494	$32,958	$25,213
ATSI	NA	NA	$15,129	$15,129
BGE	$13,644	$52,411	$48,642	$38,232
ComEd	$2,286	$9,446	$15,081	$8,938
DAY	$2,866	$11,701	$21,705	$12,091
DLCO	$3,366	$17,525	$24,179	$15,023
Dominion	$14,315	$42,922	$38,945	$32,061
DPL	$12,718	$40,530	$44,339	$32,529
JCPL	$10,527	$39,409	$44,968	$31,635
Met-Ed	$9,982	$39,409	$40,802	$30,064
PECO	$9,703	$38,311	$45,853	$31,289
PENELEC	$6,276	$24,309	$32,090	$20,892
Pepco	$16,205	$50,906	$44,233	$37,115
PPL	$9,104	$33,649	$42,872	$28,542
PSEG	$9,172	$37,626	$37,929	$28,242
RECO	$7,838	$35,022	$32,178	$25,013
PJM	$8,990	$32,781	$34,939	$25,570

9 The RPM revenue values for PJM are load-weighted average clearing prices across the relevant Base Residual Auctions.

10 The PJM capacity revenues differ slightly from those presented in Table 6-2, Table 6-5 and Table 6-8 as these capacity revenues by technology type are adjusted for technology-specific outage rates.

11 No resources in ATSI cleared in the relevant auctions. There are no capacity resources in the RECO zone.

12 The energy net revenues presented for the PJM area in this section represent the simple average of all zonal energy net revenues.

Table 6-4 Zonal combined net revenue from all markets for a CT under economic dispatch (Dollars per installed MW-year)

Zone	2009	2010	2011	Average
AECO	$70,894	$102,692	$94,495	$89,360
AEP	$40,562	$61,953	$69,177	$57,231
AP	$64,691	$95,149	$81,295	$80,378
ATSI	NA	NA	NA	NA
BGE	$90,378	$121,392	$96,979	$102,917
ComEd	$39,573	$59,824	$63,419	$54,272
DAY	$40,154	$62,079	$70,043	$57,425
DLCO	$40,654	$67,903	$72,516	$60,358
Dominion	$73,836	$106,406	$87,875	$89,373
DPL	$50,006	$90,908	$92,677	$77,864
JCPL	$70,048	$102,063	$93,306	$88,472
Met-Ed	$64,485	$102,063	$89,139	$85,229
PECO	$69,223	$100,966	$94,191	$88,127
PENELEC	$60,779	$86,964	$80,428	$76,057
Pepco	$70,708	$113,561	$92,571	$92,280
PPL	$68,625	$96,304	$91,209	$85,379
PSEG	$85,907	$106,607	$86,266	$92,927
RECO	NA	NA	NA	NA
PJM	$62,533	$92,302	$84,724	$79,853

New Entrant Combined Cycle

Energy market net revenue was calculated for a CC plant dispatched by PJM operations. For this economic dispatch scenario, it was assumed that the CC plant had a minimum run time of eight hours. The unit was first committed day ahead in profitable blocks of at least eight hours, including start up costs.[13] If the unit was not already committed day ahead, it was then run in real time in stand-alone profitable blocks of at least eight hours, or any hours bordering the profitable day ahead or real time block.

Table 6-5 PJM-wide net revenue for a CC under economic dispatch by market (Dollars per installed MW-year)

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
2009	$44,553	$50,184	$0	$0	$3,198	$97,936
2010	$89,027	$58,324	$0	$0	$3,198	$150,549
2011	$103,726	$48,306	$0	$0	$3,198	$155,230

13 All starts associated with combined cycle units are assumed to be hot starts.

Table 6-6 PJM Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year)

Zone	2009	2010	2011	Average
AECO	$53,515	$106,643	$126,869	$95,676
AEP	$25,716	$47,591	$82,324	$51,877
AP	$51,473	$91,032	$113,561	$85,356
ATSI	NA	NA	$54,554	$54,554
BGE	$56,858	$124,665	$130,806	$104,110
ComEd	$18,383	$33,906	$46,293	$32,861
DAY	$23,596	$46,647	$82,067	$50,770
DLCO	$22,923	$51,180	$81,642	$51,915
Dominion	$58,612	$116,873	$114,530	$96,672
DPL	$55,142	$106,245	$123,599	$94,995
JCPL	$52,935	$105,474	$124,878	$94,429
Met-Ed	$47,338	$97,665	$111,653	$85,552
PECO	$49,620	$99,951	$121,804	$90,458
PENELEC	$42,010	$80,773	$109,048	$77,277
Pepco	$58,923	$121,952	$121,143	$100,673
PPL	$45,115	$87,314	$111,111	$81,180
PSEG	$50,355	$101,819	$114,951	$89,041
RECO	$44,897	$93,724	$96,235	$78,285
PJM	$44,553	$89,027	$103,726	$79,102

Table 6-7 Zonal combined net revenue from all markets for a CC under economic dispatch (Dollars per installed MW-year)

Zone	2009	2010	2011	Average
AECO	$117,477	$173,539	$178,353	$156,457
AEP	$66,034	$101,513	$133,808	$100,452
AP	$110,100	$157,928	$165,046	$144,358
ATSI	NA	NA	NA	NA
BGE	$139,127	$198,247	$182,290	$173,221
ComEd	$58,700	$87,828	$97,778	$81,435
DAY	$63,914	$100,569	$133,551	$99,345
DLCO	$63,241	$105,102	$133,126	$100,490
Dominion	$122,575	$184,646	$166,637	$157,952
DPL	$95,460	$160,167	$175,084	$143,570
JCPL	$116,897	$172,370	$176,362	$155,210
Met-Ed	$105,964	$164,561	$163,137	$144,554
PECO	$113,582	$166,847	$173,288	$151,239
PENELEC	$100,637	$147,669	$160,532	$136,279
Pepco	$117,549	$188,848	$172,628	$159,675
PPL	$109,077	$154,209	$162,595	$141,961
PSEG	$132,624	$175,401	$166,435	$158,153
RECO	NA	NA	NA	NA
PJM	$102,060	$152,465	$158,791	$137,772

New Entrant Coal Plant

Energy market net revenue was calculated assuming that the CP plant had a 24-hour minimum run time and was dispatched by PJM operations in the Day Ahead market for all available plant hours, both reasonable assumptions for a large, efficient CP. The calculations account for operating reserve payments based on PJM rules, when applicable, since the assumed operation is under the direction of PJM operations. Regulation revenue is calculated for any hours in which the new entrant CP's regulation offer is below the regulation-clearing price.

Table 6-8 PJM-wide net revenue for a CP under economic dispatch by market (Dollars per installed MW-year)

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
2009	$47,467	$47,469	$0	$2,051	$1,783	$98,770
2010	$119,478	$54,670	$0	$898	$1,783	$176,830
2011	$70,665	$44,282	$0	$1,025	$1,783	$117,754

Table 6-9 PJM Energy Market net revenue for a new entrant CP under economic dispatch (Dollars per installed MW-year)

Zone	2009	2010	2011	Average
AECO	$67,257	$149,022	$75,325	$97,201
AEP	$13,379	$56,227	$72,858	$47,488
AP	$36,322	$98,671	$99,020	$78,004
ATSI	NA	NA	$27,942	$27,942
BGE	$36,606	$80,689	$56,940	$58,078
ComEd	$30,169	$106,599	$94,493	$77,087
DAY	$19,206	$77,082	$65,842	$54,043
DLCO	$14,410	$76,395	$47,075	$45,960
Dominion	$36,506	$144,290	$77,310	$86,035
DPL	$30,404	$147,279	$94,908	$90,864
JCPL	$57,382	$147,559	$71,437	$92,126
Met-Ed	$45,652	$139,228	$61,703	$82,195
PECO	$60,767	$142,542	$74,834	$92,714
PENELEC	$59,243	$122,426	$95,440	$92,369
Pepco	$54,534	$160,627	$73,476	$96,212
PPL	$55,246	$114,549	$76,697	$82,164
PSEG	$135,308	$124,533	$47,550	$102,464
RECO	$54,556	$143,410	$59,111	$85,692
PJM	$47,467	$119,478	$70,665	$79,203

Table 6-10 Zonal combined net revenue from all markets for a CP under economic dispatch (Dollars per installed MW-year)

Zone	2009	2010	2011	Average
AECO	$128,381	$211,318	$122,640	$154,113
AEP	$52,513	$106,646	$119,838	$92,999
AP	$92,558	$161,061	$145,923	$133,181
ATSI	NA	NA	NA	NA
BGE	$115,577	$149,741	$104,070	$123,129
ComEd	$69,425	$156,923	$141,347	$122,565
DAY	$58,242	$127,353	$112,811	$99,469
DLCO	$53,547	$126,764	$93,969	$91,427
Dominion	$97,920	$207,434	$125,181	$143,511
DPL	$69,771	$197,413	$142,154	$136,446
JCPL	$118,581	$209,844	$118,528	$148,984
Met-Ed	$101,945	$201,539	$108,685	$137,390
PECO	$121,923	$204,846	$121,782	$149,517
PENELEC	$115,208	$184,704	$142,161	$147,358
Pepco	$110,759	$222,926	$120,398	$151,361
PPL	$116,455	$176,936	$123,652	$139,015
PSEG	$213,276	$193,147	$95,458	$167,294
RECO	NA	NA	NA	NA
PJM	$102,255	$177,412	$121,162	$133,610

Net Revenue Adequacy

To put net revenue results in perspective, net revenues are compared to the annual, nominal levelized fixed costs for each technology. Nominal levelized fixed cost provides for the full recovery of and on capital and all the expenses of operating the facility over 20 years, at a constant nominal annual rate.

The extent to which net revenues cover the levelized fixed costs of investment is significantly dependent on technology type and location, which affect both energy and capacity revenue.

In this section, net revenue includes net revenue from the PJM Energy Market, from the PJM Capacity Market and from any applicable ancillary service.

Table 6-11 New entrant 20-year levelized fixed costs (By plant type (Dollars per installed MW-year))

	20-Year Levelized Fixed Cost		
	2009	2010	2011
Combustion Turbine	$128,705	$131,044	$110,589
Combined Cycle	$173,174	$175,250	$153,682
Coal Plant	$446,550	$465,455	$474,692

New Entrant Combustion Turbine

In 2011, no zones would have received sufficient net revenue to cover the levelized fixed costs of a new CT.

Table 6-12 Percent of 20-year levelized fixed costs recovered by CT energy and capacity net revenue (Dollars per installed MW-year)

Zone	2009	2010	2011
AECO	55%	78%	85%
AEP	32%	47%	63%
AP	50%	73%	74%
ATSI	NA	NA	NA
BGE	70%	93%	88%
ComEd	31%	46%	57%
DAY	31%	47%	63%
DLCO	32%	52%	66%
Dominion	57%	81%	79%
DPL	39%	69%	84%
JCPL	54%	78%	84%
Met-Ed	50%	78%	81%
PECO	54%	77%	85%
PENELEC	47%	66%	73%
Pepco	55%	87%	84%
PPL	53%	73%	82%
PSEG	67%	81%	78%
RECO	NA	NA	NA
PJM	49%	70%	77%

Figure 6-1 compares zonal net revenue for a new entrant CT for 2009 through 2011 to the 2011 levelized fixed cost. Figure 6-2 shows zonal net revenue for the new entrant CT for 2009 through 2011 by LDA with the applicable yearly levelized fixed cost.

Figure 6-1 New entrant CT net revenue and 20-year levelized fixed cost (Dollars per installed MW-year)

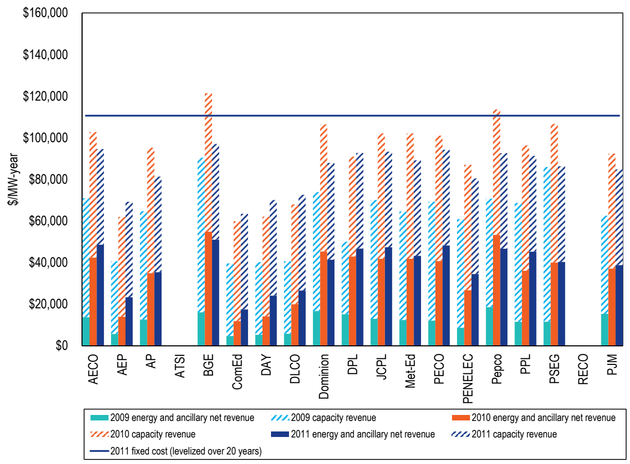


Figure 6-2 New entrant CT net revenue and 20-year levelized fixed cost by LDA (Dollars per installed MW-year)

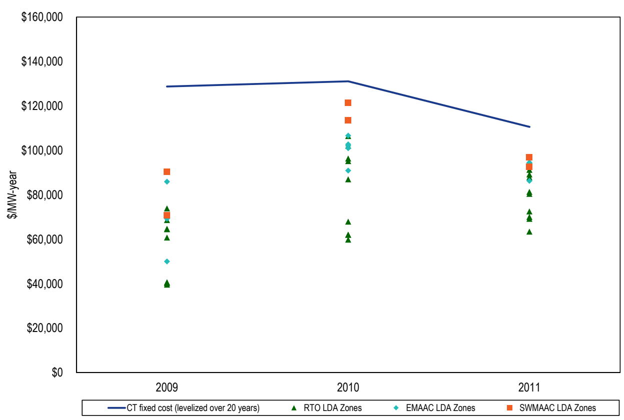
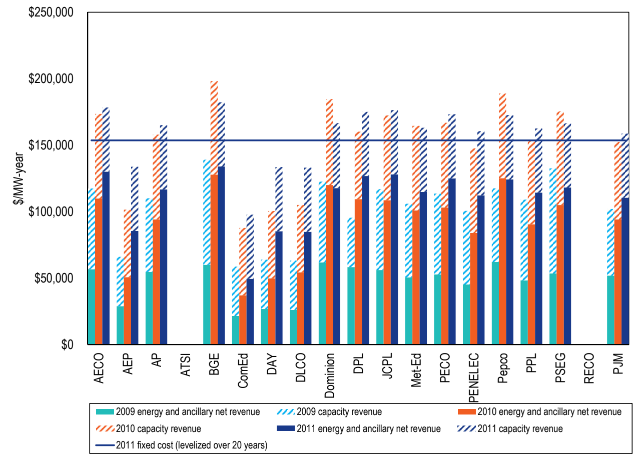


Figure 6-3 New entrant CC net revenue and 20-year levelized fixed cost (Dollars per installed MW-year)



New Entrant Combined Cycle

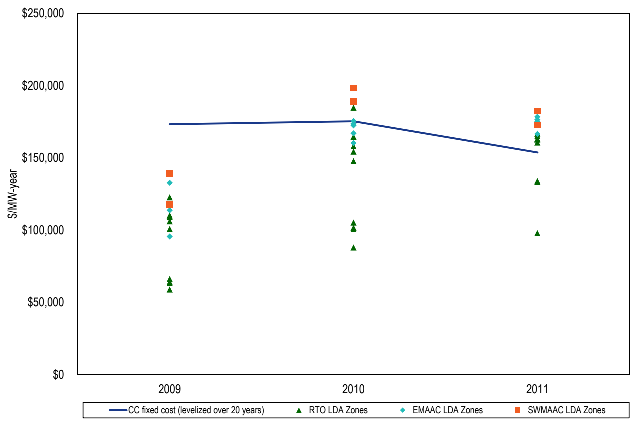
In 2011, all but four zones would have received net revenue sufficient to cover the levelized fixed costs of a new CC.

Figure 6-3 compares zonal net revenue for a new entrant CC for 2009 through 2011 to the 2011 levelized fixed cost. Figure 6-4 shows zonal net revenue for the new entrant CC for 2009 through 2011 by LDA with the applicable yearly levelized fixed cost.

Table 6-13 Percent of 20-year levelized fixed costs recovered by CC energy and capacity net revenue

Zone	2009	2010	2011
AECO	68%	99%	116%
AEP	38%	58%	87%
AP	64%	90%	107%
ATSI	NA	NA	NA
BGE	80%	113%	119%
ComEd	34%	50%	64%
DAY	37%	57%	87%
DLCO	37%	60%	87%
Dominion	71%	105%	108%
DPL	55%	91%	114%
JCPL	68%	98%	115%
Met-Ed	61%	94%	106%
PECO	66%	95%	113%
PENELEC	58%	84%	104%
Pepco	68%	108%	112%
PPL	63%	88%	106%
PSEG	77%	100%	108%
RECO	NA	NA	NA
PJM	59%	87%	103%

Figure 6-4 New entrant CC net revenue and 20-year levelized fixed cost by LDA (Dollars per installed MW-year)



New Entrant Coal Plant

In 2011, no zones would have received sufficient net revenue to cover the levelized fixed costs of a new CP. No zone received sufficient net revenue to cover even 40 percent of the levelized fixed costs.

Table 6-14 Percent of 20-year levelized fixed costs recovered by CP energy and capacity net revenue

Zone	2009	2010	2011
AECO	29%	45%	26%
AEP	12%	23%	25%
AP	21%	35%	31%
ATSI	NA	NA	NA
BGE	26%	32%	22%
ComEd	16%	34%	30%
DAY	13%	27%	24%
DLCO	12%	27%	20%
Dominion	22%	45%	26%
DPL	16%	42%	30%
JCPL	27%	45%	25%
Met-Ed	23%	43%	23%
PECO	27%	44%	26%
PENELEC	26%	40%	30%
Pepco	25%	48%	25%
PPL	26%	38%	26%
PSEG	48%	41%	20%
RECO	NA	NA	NA
PJM	23%	38%	26%

Figure 6-5 compares zonal net revenue for a new entrant CP for 2009 through 2011 to the 2011 levelized fixed cost. Figure 6-6 shows zonal net revenue for the new entrant CP for 2009 through 2011 by LDA with the applicable yearly levelized fixed cost.

Figure 6-5 New entrant CP net revenue and 20-year levelized fixed cost (Dollars per installed MW-year)

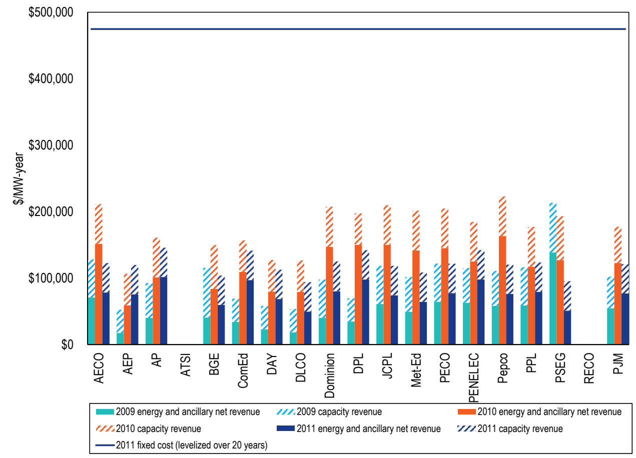
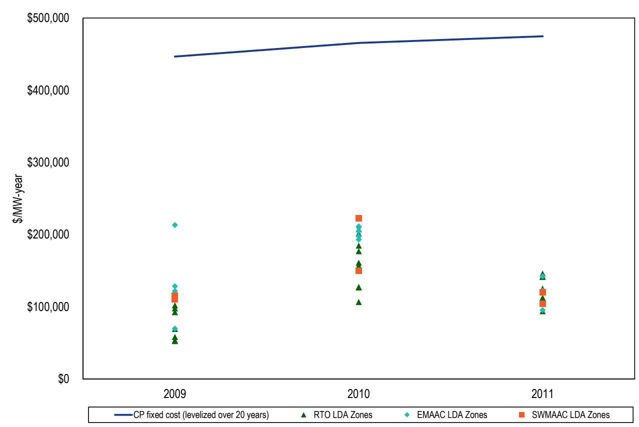


Figure 6-6 New entrant CP net revenue and 20-year levelized fixed cost by LDA (Dollars per installed MW-year)



Although it can be expected that in the long run, in a competitive market, net revenue from all sources will cover the fixed costs of investing in new generating resources, including a competitive return on investment, actual results are expected to vary from year to year. Wholesale energy markets, like other markets, are cyclical. When the markets are long, prices will be lower and when the markets are short, prices will be higher. Analysis of net revenue indicates that the contribution of capacity revenue from RPM comprises a larger share of net revenue for a new entrant CT than for the CC or CP technologies. Capacity market revenue is a smaller proportion of total net revenue for a new entrant coal plant, thus, the incentive to invest in a new entrant CP is less dependent on capacity revenues and more

Table 6-15 Internal rate of return sensitivity for CT, CC and CP generators

	CT		CC		CP	
	20-Year Levelized Net Revenue	20-Year After Tax IRR	20-Year Levelized Net Revenue	20-Year After Tax IRR	20-Year Levelized Net Revenue	20-Year After Tax IRR
Sensitivity 1	$118,089	13.8%	$163,682	13.7%	$504,692	13.7%
Base Case	$110,589	12.0%	$153,682	12.0%	$474,692	12.0%
Sensitivity 2	$103,089	10.1%	$143,682	10.2%	$444,692	10.3%
Sensitivity 3	$95,589	8.1%	$133,682	8.4%	$414,692	8.5%
Sensitivity 4	$88,089	6.0%	$123,682	6.4%	$384,692	6.6%
Sensitivity 5	$80,589	3.5%	$113,682	4.3%	$354,692	4.6%
Sensitivity 6	$73,089	0.5%	$103,682	1.9%	$324,692	2.4%

dependent on energy prices, input costs and energy net revenues.

The net revenue for a new generation resource varied significantly with the input fuel type and the efficiency of the reference technology. In 2011, the yearly average operating cost of the CC was lower than the average operating costs of the CP, driven by the decreasing cost of gas and increasing cost of coal.

The net revenue results illustrate some fundamentals of the PJM wholesale power market. CTs are generally the highest incremental energy cost units and therefore tend to be marginal in the energy market and set prices in the energy market, when they run. When this occurs, CT energy market net revenues are small and there is little contribution to fixed costs. High demand hours result in less efficient CTs setting prices, which results in higher net revenues for more efficient CTs. Scarcity revenues in the energy market also contribute to covering fixed costs, when they occur, but scarcity revenues are not a predictable and systematic source of net revenue. In the PJM design, the balance of the net revenue required to cover the fixed costs of peaking units comes from the capacity market. However, there may be a lag in capacity market prices which either offsets the reduction in energy market revenues or exacerbates the reduction in energy market revenues. Capacity market prices are a function of a three year historical average net revenue offset which can be an inaccurate estimate of actual net revenues in the current operating year. Capacity market prices and revenues have a substantial impact on the profitability of investing in CTs and CCs. In 2011, zonal energy net revenues increased significantly for most CCs and CTs, while capacity market prices decreased in all zones. As a result, there were some zones that, when both energy revenues and capacity revenues are considered, showed revenue adequacy for a new entrant CC in 2011.

Coal units (CP) are marginal in the PJM system for a substantial number of hours. When this occurs, CP energy market net revenues are small and there is little contribution to fixed costs. However, when less efficient coal units are on the margin net revenues are higher for more efficient coal units. Coal units also received higher net revenues as a result of CTs setting prices based on gas costs.

The returns earned by investors in generating units are a direct function of net revenues, the cost of capital, and the fixed costs associated with the generating unit. Positive returns may be earned at less than the annualized fixed costs, although the returns are less than the target. A sensitivity analysis was performed to determine the impact of changes in net revenue on the return on investment for a new generating unit. The internal rate of return (IRR) was calculated for a range of 20-year levelized net revenue streams, using 20-year levelized fixed costs from Table 6-11. The results are shown in Table 6-15.[14]

Additional sensitivity analyses were performed for the CT and the CC technologies for the debt to equity ratio; the term of the debt financing; and the costs of interconnection. Table 6-16 shows the levelized annual revenue requirements associated with a range of debt to equity ratios holding the 12 percent IRR constant. The base case assumes 50/50 debt to equity ratio. As the percent of equity financing decreases, the levelized annual revenue required to earn a 12 percent IRR

14 This analysis was performed for the MMU by Pasteris Energy, Inc. The annual costs were based on a 20-year project life, 50/50 debt-to-equity financing with a target IRR of 12 percent and a debt rate of 7 percent. For depreciation, the analysis assumed a 15-year modified accelerated cost-recovery schedule (MACRS) for the CT plant and 20-year MACRS for the CC and CP plants. A general annual rate of cost inflation of 2.5 percent was utilized in all calculations.

falls. Table 6-17 shows the levelized annual revenue requirements associated with various terms for the debt financing, assuming a 50/50 debt to equity ratio and 12 percent rate of return. As the term of the debt financing decreases, more net revenue is required annually to maintain a 12 percent rate of return.

Table 6-16 Debt to equity ratio sensitivity for CT and CC assuming 20 year debt term and 12 percent internal rate of return

	Equity as a percentage of total financing	CT levelized annual revenue requirement	CC levelized annual revenue requirement
Sensitivity 1	60%	$117,666	$163,034
Sensitivity 2	55%	$114,127	$158,358
Base Case	50%	$110,589	$153,682
Sensitivity 3	45%	$107,050	$149,006
Sensitivity 4	40%	$103,512	$144,330
Sensitivity 5	35%	$99,974	$139,654
Sensitivity 6	30%	$96,435	$134,978

Table 6-17 Debt term sensitivity for CT and CC assuming 50/50 debt to equity ratio and 12 percent internal rate of return

	Term of debt in years	CT levelized annual revenue requirement	CC levelized annual revenue requirement
Sensitivity 1	30	$99,512	$139,050
Sensitivity 2	25	$103,698	$144,582
Base Case	20	$110,589	$153,682
Sensitivity 3	15	$116,378	$161,332
Sensitivity 4	10	$124,054	$171,475

Table 6-18 shows the impact of a range of assumed interconnection costs on the levelized annual revenue requirement for the CT and the CC technologies. Interconnection costs vary significantly by location across PJM and even within PJM zones and can significantly impact the profitability of investing in peaking and midmerit generation technologies in a specific location. The impact on the annualized revenue requirements is more substantial for CTs than for CCs as interconnection costs are a larger proportion of overall project costs for CTs and as the new entrant CC has a higher energy output over which to spread the costs than the new entrant CT.

Actual Net Revenue

This analysis of net revenues is based on actual net revenues for actual units operating in PJM. Net revenues from energy and capacity markets are compared to avoidable costs to determine the extent to which the revenues from PJM markets provide sufficient incentive for continued operations in PJM Markets. Avoidable costs are the costs which must be paid each year in order to keep a unit operating. Avoidable costs are less than total fixed costs, which include the return on and of capital, and more than marginal costs, which are the purely short run incremental costs of producing energy. It is rational for an owner to continue to operate a unit if it is covering its avoidable costs and therefore contributing to covering fixed costs. It is not rational for an owner to continue to operate a unit if it is not covering and not expected to cover its avoidable costs. As a general matter, under those conditions, retirement of the unit is the logical option. Thus, this comparison of actual net revenues to avoidable costs is a measure of the extent to which units in PJM may be at risk of retirement.

The definition of avoidable costs, based on the RPM rules, includes both avoidable costs and the annualized fixed costs of investments required to maintain a unit as a capacity resource (APIR). When actual net revenues are compared to actual avoidable costs, the actual avoidable costs include APIR when unit owners have included APIR in unit offers. This affects the interpretation of the conclusions. Existing APIR is a sunk cost and a rational decision about retirement would ignore such

Table 6-18 Interconnection cost sensitivity for CT and CC

	CT			CC		
	Capital cost ($000)	Percent of total capital cost	Annualized revenue requirement ($/ICAP-Year)	Capital cost ($000)	Percent of total capital cost	Annualized revenue requirement ($/ICAP-Year)
Sensitivity 1	$0	0%	$107,213	$0	0%	$150,034
Sensitivity 2	$4,811	2%	$108,900	$7,692	1%	$151,858
Base Case	$9,622	3%	$110,589	$15,383	2%	$153,682
Sensitivity 3	$14,433	5%	$112,277	$23,075	4%	$155,507
Sensitivity 4	$19,244	6%	$113,965	$30,766	5%	$157,331
Sensitivity 5	$24,055	8%	$115,653	$38,458	6%	$159,155
Sensitivity 6	$28,866	9%	$117,341	$46,149	7%	$160,980
Sensitivity 7	$50,000	16%	$124,756	$50,000	8%	$161,893
Sensitivity 8	$75,000	24%	$133,531	$75,000	11%	$167,822
Sensitivity 9	$100,000	32%	$142,302	$100,000	15%	$173,751

Table 6-19 Class average net revenue from energy and ancillary markets and associated recovery of class average avoidable costs and total revenue from all markets and associated recovery of class average avoidable costs

Technology	Total Installed Capacity (ICAP)	Class average energy and ancillary net revenue ($/MW-year)	Class average energy net revenue and capacity revenue ($/MW-year)	Class average avoidable costs ($/MW-year)
CC - NUG Cogeneration Frame B or E Technology	2,236	$15,109	$59,208	$33,169
CC - Two of Three on One Frame F Technology	15,235	$73,628	$120,348	$18,215
CT - First & Second Generation Aero (P&W FT 4)	3,702	$7,436	$52,014	$15,486
CT - First & Second Generation Frame B	3,764	$4,574	$49,920	$12,398
CT - Second Generation Frame E	10,619	$22,231	$67,715	$7,217
CT - Third Generation Aero	3,696	$26,132	$73,816	$16,073
CT - Third Generation Frame F	9,026	$24,920	$69,935	$9,178
Diesel	495	$43,441	$86,074	$7,552
Hydro	1,975	$209,469	$254,535	$25,618
Nuclear	29,741	$240,376	$284,895	NA
Oil or Gas Steam	9,015	$22,308	$62,952	$46,228
Pumped Storage	4,952	$11,586	$61,158	$15,036
Sub-Critical Coal	31,096	$60,180	$98,485	$69,503
Super Critical Coal	24,653	$77,487	$111,428	$96,249

sunk costs. Potential APIR is not a sunk cost and a rational decision about retirement would consider the expected probability of recovering the costs of such new investments over the remaining life of the unit.

The MMU calculated unit specific energy and ancillary service net revenues for several technology classes. These net revenues were compared to avoidable costs to determine the extent to which PJM Energy and Ancillary Service Markets alone provide sufficient incentive for continued operations in PJM Markets. Energy and Ancillary Service revenues were then combined with the actual capacity revenues, and compared to actual avoidable costs to determine the extent to which the capacity market revenues covered any shortfall between energy and ancillary net revenues and avoidable costs. The comparison of the two results is an indicator of the significance of the role of the capacity market in maintaining the viability of existing generating units.

Actual energy net revenues include Day-Ahead and balancing energy revenues, less submitted or estimated operating costs, as well as any applicable Day-Ahead or Balancing Operating Reserve Credits. Ancillary service revenues include actual unit credits for regulation services, spinning reserves and black start capability, in addition to actual or class average reactive revenues determined by actual FERC filings.

The MMU calculated average avoidable costs in dollars per MW-year based on actual submitted Avoidable Cost Rate (ACR) data for units associated with the most recent 2010/2011 and 2011/2012 RPM Auctions.[15] For units that did not submit ACR data, the default ACR was used.

The RPM capacity market design provides supplemental signals to the market based on the locational and forward-looking need for generation resources to maintain system reliability. For this analysis, unit specific capacity revenues associated with the 2010/2011 and 2011/2012 delivery years, reflecting commitments made in Base Residual Auctions (BRA) and subsequent Incremental Auctions, net of any performance penalties, were added to unit specific energy and ancillary net revenues to determine total revenue from PJM Markets. Any unit with a significant portion of installed capacity designated as FRR committed was excluded from the analysis.[16] For units exporting capacity, the applicable Base Residual Auction (BRA) clearing price was applied, which may understate actual revenues, since units may bid an export price into the auction as an opportunity cost and provide capacity to the market with the higher price.

Net revenues were analyzed for most technologies for which avoidable costs are developed in the RPM. The underlying analysis was done on a unit specific basis, using individual unit actual net revenues and individual unit avoidable costs. Table 6-19 provides a summary of

15 If a unit submitted updated ACR data for an incremental auction, that data was used instead of the ACR data submitted for the Base Residual Auction.

16 The MMU cannot assess the risk of FRR designated units because the incentives associated with continued operations for these units are not transparent and are not aligned with PJM market incentives. For the same reasons, units with significant FRR commitments are excluded from the analysis of units potentially facing significant capital expenditures associated with environmental controls.

Table 6-20 Energy and ancillary service net revenue by quartile for select technologies for calendar year 2011

	Energy and ancillary net revenue ($/MW-year)		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	$7,443	$26,432	$90,547
CC - Two of Three on One Frame F Technology	$35,131	$79,038	$102,517
CT - First & Second Generation Aero (P&W FT 4)	$1,960	$4,765	$11,467
CT - First & Second Generation Frame B	$1,128	$3,940	$7,799
CT - Second Generation Frame E	$6,096	$12,826	$33,589
CT - Third Generation Aero	$14,222	$25,227	$34,658
CT - Third Generation Frame F	$10,139	$16,559	$34,776
Diesel	$1,475	$1,990	$5,967
Hydro	$103,780	$202,072	$250,008
Nuclear	$183,106	$266,044	$294,493
Oil or Gas Steam	$1,452	$4,644	$13,004
Pumped Storage	$0	$2,606	$5,064
Sub-Critical Coal	$24,072	$56,123	$86,062
Super Critical Coal	$55,366	$78,780	$97,698

Table 6-21 Capacity revenue by quartile for select technologies for calendar year 2011

	Capacity revenue ($/MW-year)		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	$41,866	$46,794	$47,855
CC - Two of Three on One Frame F Technology	$47,291	$48,149	$49,010
CT - First & Second Generation Aero (P&W FT 4)	$41,809	$44,306	$48,973
CT - First & Second Generation Frame B	$39,182	$47,120	$49,436
CT - Second Generation Frame E	$45,732	$48,737	$49,858
CT - Third Generation Aero	$46,208	$48,862	$49,575
CT - Third Generation Frame F	$44,177	$47,573	$48,533
Diesel	$43,492	$47,175	$51,437
Hydro	$44,259	$48,567	$49,858
Nuclear	$48,015	$49,023	$49,418
Oil or Gas Steam	$40,175	$46,396	$48,534
Pumped Storage	$48,932	$49,181	$49,459
Sub-Critical Coal	$41,468	$46,071	$48,239
Super Critical Coal	$24,231	$44,686	$47,074

Table 6-22 Combined revenue from all markets by quartile for select technologies for calendar year 2011

	Energy, ancillary, and capacity revenue ($/MW-year)		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	$49,310	$73,226	$138,402
CC - Two of Three on One Frame F Technology	$82,422	$127,186	$151,527
CT - First & Second Generation Aero (P&W FT 4)	$43,769	$49,071	$60,440
CT - First & Second Generation Frame B	$40,310	$51,060	$57,235
CT - Second Generation Frame E	$51,828	$61,563	$83,447
CT - Third Generation Aero	$60,430	$74,089	$84,233
CT - Third Generation Frame F	$54,316	$64,132	$83,309
Diesel	$44,966	$49,165	$57,404
Hydro	$148,039	$250,639	$299,865
Nuclear	$231,121	$315,067	$343,911
Oil or Gas Steam	$41,627	$51,040	$61,538
Pumped Storage	$48,932	$51,787	$54,523
Sub-Critical Coal	$65,539	$102,195	$134,302
Super Critical Coal	$79,597	$123,466	$144,772

results by technology class, as well as the total installed capacity associated with each technology analyzed.

The actual unit specific energy and ancillary net revenues, avoidable costs and capacity revenues underlying the class averages shown in Table 6-19 incorporate a wide range of results. In order to illustrate this underlying variability while preserving confidentiality of unit specific information, the data are aggregated and summarized by quartile. Within each technology, quartiles were established based on the distribution of total energy net revenue received per installed MW-year. These quartiles remain constant throughout the analysis and are useful in presenting the range of data

Table 6-23 Avoidable cost recovery by quartile from energy and ancillary net revenue for select technologies for calendar year 2011

	Recovery of avoidable costs from energy and ancillary net revenue		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	54%	157%	435%
CC - Two of Three on One Frame F Technology	226%	363%	807%
CT - First & Second Generation Aero (P&W FT 4)	23%	65%	104%
CT - First & Second Generation Frame B	12%	37%	83%
CT - Second Generation Frame E	92%	144%	363%
CT - Third Generation Aero	130%	161%	228%
CT - Third Generation Frame F	106%	187%	291%
Diesel	6%	38%	1,731%
Hydro	663%	882%	950%
Nuclear	NA	NA	NA
Oil or Gas Steam	3%	10%	38%
Pumped Storage	NA	NA	NA
Sub-Critical Coal	31%	89%	140%
Super Critical Coal	89%	139%	212%

Table 6-24 Avoidable cost recovery by quartile from all PJM Markets for select technologies for calendar year 2011

	Recovery of avoidable costs from all markets		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	220%	296%	635%
CC - Two of Three on One Frame F Technology	460%	726%	1,100%
CT - First & Second Generation Aero (P&W FT 4)	282%	522%	676%
CT - First & Second Generation Frame B	362%	530%	672%
CT - Second Generation Frame E	659%	709%	921%
CT - Third Generation Aero	387%	573%	632%
CT - Third Generation Frame F	609%	789%	959%
Diesel	420%	707%	2,735%
Hydro	849%	1,061%	1,163%
Nuclear	NA	NA	NA
Oil or Gas Steam	87%	177%	209%
Pumped Storage	186%	443%	664%
Sub-Critical Coal	90%	148%	203%
Super Critical Coal	127%	201%	284%

while avoiding the influence of outliers. The the three break points between the quartiles are presented. Table 6-20 shows average energy and ancillary service net revenues by quartile for select technology classes.

Differences in energy net revenue within technology classes reflect differences in incremental costs which are a function of plant efficiencies, input fuels, variable operating and maintenance (VOM) expenses and emission rates, as well as differences in location which affect both the LMP and delivery costs associated with input fuels. The average net revenues for diesel units, the oil or gas-fired steam technology, and several of the older CT technologies reflect both units burning natural gas and units burning oil distillates. The geographical distribution of units for a given technology class across the PJM footprint determines individual unit price levels and thus significantly affects average energy net revenue for that technology class.

Table 6-23 shows the avoidable cost recovery from PJM energy and ancillary services markets by quartiles. In 2011, a substantial portion of units did not achieve full recovery of avoidable costs through energy markets alone.

Table 6-24 shows the avoidable cost recovery from all PJM markets by quartiles. In 2011, the majority of units in all technology classes received energy, ancillary and capacity revenue well in excess of avoidable costs.

Table 6-25 shows the proportion of units recovering avoidable costs from energy and ancillary services markets and from all markets for 2009, 2010 and 2011. Since 2009, RPM capacity revenues were sufficient to cover the shortfall between energy revenues and avoidable costs for the majority of units in PJM.

Table 6-25 Proportion of units recovering avoidable costs from energy and ancillary markets as well as total markets for calendar years 2009 to 2011

	2009		2010		2011	
Technology	Units with full recovery from energy and ancillary markets	Units with full recovery from all markets	Units with full recovery from energy and ancillary markets	Units with full recovery from all markets	Units with full recovery from energy and ancillary markets	Units with full recovery from all markets
CC - NUG Cogeneration Frame B or E Technology	57%	96%	83%	92%	64%	89%
CC - Two of Three on One Frame F Technology	63%	89%	84%	100%	87%	97%
CT - First & Second Generation Aero (P&W FT 4)	24%	99%	34%	100%	32%	99%
CT - First & Second Generation Frame B	30%	100%	34%	98%	29%	94%
CT - Second Generation Frame E	60%	100%	67%	100%	82%	100%
CT - Third Generation Aero	23%	99%	49%	99%	87%	99%
CT - Third Generation Frame F	41%	98%	69%	100%	79%	98%
Diesel	69%	97%	71%	97%	61%	91%
Hydro	100%	100%	100%	100%	96%	100%
Nuclear	100%	100%	100%	100%	100%	100%
Oil or Gas Steam	36%	90%	40%	87%	43%	86%
Pumped Storage	45%	100%	90%	100%	70%	100%
Sub-Critical Coal	66%	88%	73%	88%	63%	77%
Super Critical Coal	74%	91%	77%	80%	81%	88%

For both the CT technologies and the CC technology, RPM revenue has provided an adequate supplemental revenue stream to incent continued operations in PJM for most units that do not recover 100 percent of fixed costs through energy market revenue.

A significant number of sub-critical and supercritical coal units did not recover avoidable costs from energy market revenues alone in 2011. With significantly higher avoidable costs than CCs and CTs and typically lower operating costs per MWh, the profitability of operating coal units relies more heavily on energy market revenues.

At-Risk Coal Plants

A number of sub-critical and supercritical coal units did not recover avoidable costs even including capacity market revenues. These units are considered at risk of retirement.

Units that have either already started the deactivation process or are expected to request deactivation are excluded from the at-risk analysis.[17]

Energy market net revenues are a function of energy prices and operating costs. Avoidable costs are a function of technology, unit size and age of units and, in some cases, unit specific investments needed to maintain or enhance reliability or to comply with environmental regulations.

Table 6-26 compares characteristics of the subset of coal units with less than 100 percent recovery of avoidable costs after capacity revenues, to characteristics of coal plants with greater than or equal to 100 percent recovery. Units that did not cover their avoidable costs were, on average, less efficient and ran less often.

Units that did not cover avoidable costs generally sold capacity in RPM auctions, but some showed reduced capacity market revenues which may be attributable to partial clearing in Base Residual Auctions (BRA), high outage rates affecting the unforced capacity level that can be offered, or performance penalties associated with nonperformance. Units that did not cover avoidable costs tended to have higher avoidable costs. It is possible that these units cleared in the capacity market at a level below avoidable cost recovery due to the lag in market revenues used to calculate offer caps associated with each delivery year which led to an offer cap that understated the annual recovery needed from the RPM, or, these units may have been offered at a price below the avoidable cost based offer cap, including APIR. Such offers are rational, for example, if project costs are considered sunk, or if the project life is longer than the PJM defined recovery period for the calculation of the avoidable cost rate. In either case, these units may be at a lower risk of retirement than units under recovering

17 This is based on information provided to PJM at its request by generation owners indicating their plans for retirements, retrofits, and related retrofits outage schedules to the extent they were known and understood by generation owners following the issuance of the final MATS rule.

avoidable costs exclusive of the recovery of capital investments.

Table 6-26 Profile of coal units

	Coal plants with less than full recovery of avoidable costs	Coal plants with full recovery of avoidable costs
Total Installed Capacity (ICAP)	5,642	36,383
Avg. Installed Capacity (ICAP)	235	319
Avg. Age of Plant (Years)	46	38
Avg. Heat Rate (Btu/kWh)	11,135	10,701
Avg. Run Hours (Hours)	4,300	5,627
Avg. Avoidable Costs ($/MW-year)	512	146

In 2011, 73 coal units had capacity less than or equal to 200 MW. Of these units, 19 percent did not cover their avoidable costs. The risk of deactivation for these units depends on the degree to which revenues from all markets are less than avoidable costs. Table 6-27 shows the installed capacity (MW) associated with levels of recovery for coal plants.

Table 6-27 Installed capacity associated with levels of avoidable cost recovery: Calendar year 2011

Groups of coal plants by percent recovery of avoidable cost	Installed capacity (MW)	Percent of total
0% - 65%	3,793	9%
65% - 75%	111	0%
75% - 90%	465	1%
90% - 100%	1,273	3%
> 100%	36,383	87%
Total	42,025	100%

Impact of Environmental Rules

Environmental rules may affect decisions about investments in existing units, investment in new units and decisions to retire units. There are pending regulations that would require significant capital expenditures on environmental controls for existing units. These capital expenditures, if required, would significantly impact the profitability of coal plants lacking sufficient environmental controls. Coal plants facing capital expenditures may be retired if it is not expected that the plants will recover the associated costs through a combination of energy or capacity revenue. The extent to which capital expenditures affect an individual unit's offer in the capacity market depends upon the size of the unit, the level of investment required, the life and recovery rate of the investment, avoidable costs, and the expected net revenue.

The MMU analyzed the impact that pending environmental regulations regarding SO_2 and NO_X emissions and particulate control may have on coal plants in the PJM footprint.[18] A number of coal plants that would have had to invest in MATS compliant environmental technology have either already started the deactivation process or are expected to request deactivation.[19] Units lacking MATS compliant controls for NO_X emissions, SO_2 emissions, particulates, or all three, were identified as units potentially facing significant capital expenditures on environmental control technologies. Table 6-28 shows the number of units and associated installed capacity lacking MATS compliant environmental controls.

Table 6-28 Coal plants lacking MATS compliant environmental controls

	Coal plants without NO_X controls	Coal plants without SO_2 controls	Coal plants without particulate controls	Coal plants lacking NO_X, SO_2, and particulate controls
Number of units	62	41	52	23
Installed capacity (ICAP)	11,806	7,441	13,806	2,980

Table 6-29 compares attributes of coal plants with controls in place to units that lack controls for NO_X emissions, SO_2 emissions, particulates, or all three.

The MMU estimated the cost of installing MATS compatible environmental controls for each unit to determine at risk units.[20] Table 6-30 shows at risk units, which include units that did not cover their avoidable costs from all market revenues in addition to units that would not be able to cover the cost of installing MATS compliant environmental controls from all market revenues. A comparison of Table 6-30 to Table 6-26 shows that only 122 MW of additional coal capacity, for which plans to retire have not already been indicated, are at risk due to MATS compliance. The additional MW of coal capacity at risk to due to MATS compliance risk increases 1,294 MW if the threshold is increased to 125 percent recovery of avoidable costs.

18 FRR committed units are excluded from this analysis since they receive compensation out of PJM Markets.

19 This is based on information provided to PJM at its request by generation owners indicating their plans for retirements, retrofits, and related retrofits outage schedules to the extent they were known and understood by generation owners following the issuance of the final MATS rule.

20 Costs of environmental controls provided by Pasteris Energy, Inc.

Table 6-29 Attributes of coal plants with and without MATS compliant environmental controls

	Coal plants lacking NO_x, SO_2, or particulate controls	Coal plants with NO_x, SO_2, and particulate controls
Number of units (excluding announced or expected deactivations)	80	58
ICAP within MAAC	6,618	5,247
ICAP in rest of RTO	10,487	19,674
Total installed capacity (ICAP)	17,104	24,921
ICAP associated with plants older than 40 years	14,248	9,216
ICAP associated with small coal plants (200 MW or less)	5,958	2,001
ICAP associated with medium coal plants (200 to 500 MW)	2,495	4,915
ICAP associated with large coal plants (500 MW or greater)	8,652	18,005
ICAP associated with 100 percent recovery of avoidable costs	14,927	21,456
ICAP associated with less than 100 percent recovery of avoidable costs	2,177	3,465

Table 6-30 At risk coal plants

	Coal plants covering less than	
	100% of avoidable costs or 100% of APIR (if any)	125% of avoidable costs or 125% of APIR (if any)
Number of units	26	30
ICAP within MAAC	1,630	1,765
ICAP in rest of RTO	4,135	5,172
Total installed capacity (ICAP)	5,764	6,936