Imperial College Business School | Master of Science
Climate Change, Management & Finance

# Evaluating the Financial Viability of Power Generation with Merchant Market Exposure

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## Abstract

The 1990's deregulation of the United States power markets were intended to foster competition within power generation, with the hope of lowering electricity prices for end-use customers. In order to foster competition, deregulation started with the restructuring of vertically integrated utilities, requiring them to divest their generating assets while maintaining control of transmission and distribution systems as they were natural monopolies.

Current deregulated energy markets set energy clearing prices at the marginal generator's short run marginal cost. These market structures raise doubt to the ability of energy markets to provide sufficient financial returns to support capital investment. This paper investigates the financial profitability of a hypothetical solar photovoltaic, wind, natural gas single and combined cycle power plant in five deregulated power markets in the United States. The results of the paper highlight the economic realities of energy markets, namely that fully merchant power plants are largely unable to recover capital investments without financial incentives and long term offtake structures.

## Introduction

In 1990, in an effort to provide end use customers with access to affordable and reliable electricty, many regions in the United States began to restructure and transition from a regulated to a deregulated electricity system (Joskow, 2019).

Regulated electricty systems were operated as a monopoly where a single utility would own the entire power system, including the generating assets, transmission and distribution systems, and the contracts with end customers. The utility charged customers a predetermined retail price which was established by regulators in order to provide the utility with a guaranteed rate of return. This rate of return allowed the utility to invest in and operate the power grid. This structure placed the risk of all investments on the end customers as utilities were not deeply concerned with the efficiency of their system as their investments and operating costs were always guaranteed through the specified rate of return (Cleary & Palmer, 2020). For example, in 2018, South Carolina Electric & Gas Company (SCE&G's) had to abandon a set of nuclear power plants before reaching commercial operation due to construction cost overruns. Owing to the regulated nature of the energy market in South Carolina, SCE&G's 720,000 customers had to pay an additional $2.3 billion in order to provide the utility with their guaranteed 9.9% rate of return (Brown & Moore, 2018).

In a deregulated energy market, power generators compete in a structured, bid based market, in which they sell energy to load serving entities, who then sell the energy to end customers (Gifford et al., 2017). Energy markets are operated by regional transmission organizations (RTOs); in the United States, seven RTOs have evolved and are shown in Figure 1.

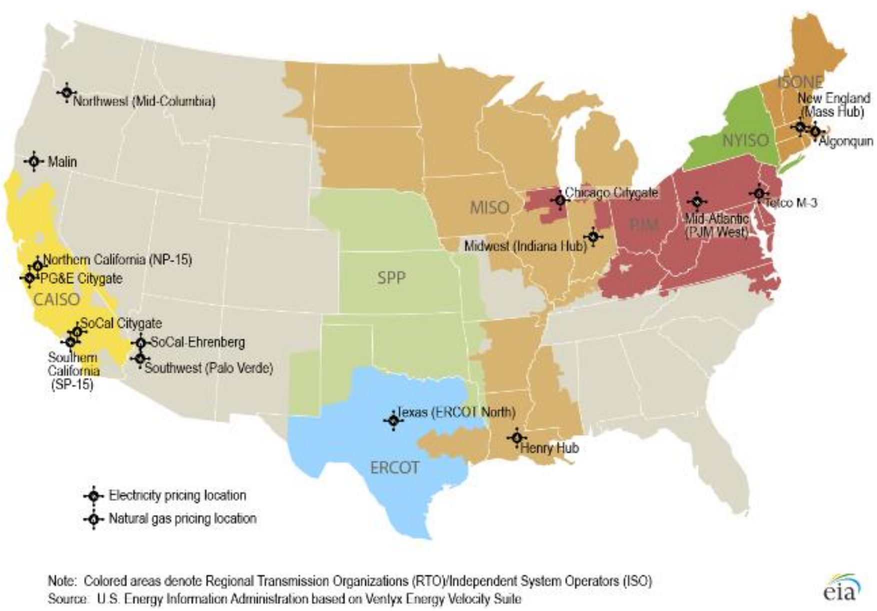


*Figure 1. Map of the United States with RTOs highlighted (US EIA, 2021).*

In the operations of the energy markets, generators offer electricty from their power plant into either the day ahead or real time market at that specific generator's short run marginal cost of generation. Day ahead bids are collected the day prior to dispatch (Blumsack, 2018). Once the bids are received, they are stacked in ascending economic order. Least cost generators are dispatched first until the forecasted demand is met, at which the clearing price is set. The clearing price, formally known as the day ahead locational marginal price (DA LMP), is paid to all dispatched generators, regardless of their initial bid (Cleary & Palmer, 2020). A hypothetical dispatch curve is shown in Figure 2. On the x-axis is the cumulative system capacity in GWs and on the y-axis is the short run marginal cost that a generator offered into the market ($ per MWh). Renewables can be seen to offer $0 per MWh, their marginal cost of generation, while petroleum generation offers a price that reflects their larger marginal cost of generation. In the example below, if demand was forecasted at 67 GWs, the last generator to meet demand, known as the marginal generator, is a “natural gas – combined cycle” plant, and the clearing price would be set at about $45 per MWh. All generators to the left of the demand curve will be paid that clearing price, regardless of their initial bid while generators to the right of the demand curve will not be dispatched.

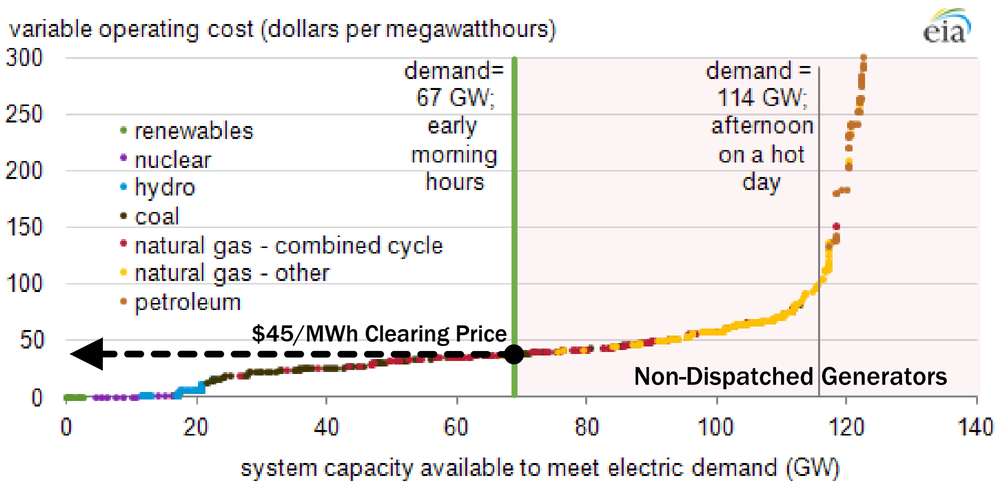


*Figure 2. Hypothetical dispatch curve highlighting various generation technologies (US EIA, 2021).*

Previous and ongoing work indicates that deregulated power markets have an important role to play in decarbonizing the power grid (MIT Energy Initiative, 2018). With fitting market guidelines provided by grid operators, power markets have the potential to provide the necessary financial indicators to initiate investments in renewable energy (Joskow & Schmalensee, 1985). However, the results from these past studies indicate a need for further, more systematic, studies to understand the ability of current power markets to provide adequate investment guidance

The goal of this paper is to evaluate the ability for power generation technologies to achieve an adequate return on investment from deregulated wholesale power markets. In doing so, two questions are asked. First, do exisiting power markets incentivize merchant generators to invest in and operate generation facilities? If competitive power markets are to provide reliable, low-cost power to end customers, they must provide an ample rate of return in order to incentivize investment. Second, to what extend does current market design promote renewable power generation? As the transition to low carbon generation accelerates, zero marginal cost generation increasingly sets energy market clearing prices at zero, further doubting the profitability of energy markets. The results from this paper highlight the financial risks power producers are exposed to when participating in wholesale power markets and help policy makers understand the economic realities of deregulated power markets.

## Data Description

This study uses three primary datasets to model power plant operations and compute the associated profitability: DA LMPs, capacity prices and natural gas spot prices. DA LMPs are attained for the following RTOs: ISO-New England (ISONE), Electric Reliability Council of Texas (ERCOT), Midcontinent ISO (MISO), Pennsylvania New Jersey and Maryland Interconnection (PJM), and the California ISO (CAISO). These grid regions were selected to represent five of the major North American RTOs and provide geographic range across the United States. The locations and associated markets are presented in Table 1.

| RTO Regions | Energy Market | Capacity Market | Natural Gas Market Node |
|---|---|---|---|
| MISO Illinois Hub | Yes;<br>5-min interval LMP | Yes;<br>Planning Resource Auction | Midwest Indiana Hub;<br>daily interval |
| PJM Dominion | Yes;<br>5-min interval LMP | Yes;<br>Reliability Pricing Model | Dominion Hub;<br>daily interval |
| CAISO ZP26 | Yes;<br>5-min interval LMP | No | PG&E City Gate;<br>daily interval |
| ERCOT Houston | Yes;<br>5-min interval LMP | No | Henry Hub;<br>daily interval |
| NYISO Zone G | Yes;<br>5-min interval` LMP | Yes;<br>Installed Capacity Market | Transco Z6;<br>daily interval |

*Table 1. RTOs and associated markets used in analysis (Moore & Giannetti, 2021).*

Energy and capacity pricing data was acquired directly through the RTO websites (CAISO, 2021; ERCOT, 2021; MISO, 2021; NYISO, 2021; PJM, 2021). Natural gas market data was acquired through the Chicago Mercantile Exchange datahub (Chicago Mercantile Exchange, 2021). Due to historical dataset availability, the analysis timeframe was limited to 10 years, between January 1, 2011 and December 31, 2020. Appendices 1, 2, and 3 illustrate the hourly DA LMP, annual capacity auction price, and the daily natural gas price.

In this study, four power generation technologies are studied, including a natural gas combustion turbine combined cycle (NGCT CC) plant, natural gas combustion turbine simple cycle (NGCT SC) plant, onshore wind plant, and a single axis tracking solar photovoltaic (PV) plant. Each hypothetical power plant was modeled with a net capacity of 400 MWac with engineering configurations based on the U.S. Energy Information Administration's Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power report cases (US Energy Information Administration & Sargent & Lundy, 2019). Power plant performance and cost characteristic are displayed in Table 2.

| Electricty Generation Typology | EIA Technology Case No. | Net Capacity (MWac) | Heat Rate HHV (Btu/kWh) | Economic Life (Years) | Overnight Capital Cost ($/kW) | VOM ($/MWh) | FOM ($/kW-yr) |
|---|---|---|---|---|---|---|---|
| NGCT Combined Cycle 2x2x1 | 7 | 400 | 6,370 | 25 | 958 | 1.87 | 12.20 |
| NGCT Simple Cycle | 6 | 400 | 9,905 | 25 | 713 | 4.50 | 7.00 |
| Onshore Wind | 20 | 400 | NA | 25 | 1,265 | 0.00 | 26.34 |
| Solar PV w/ Single Axis Tracking | 24 | 400 | NA | 25 | 1,313 | 0.00 | 15.25 |

*Table 2. Power plant performance and cost characteristics (US Energy Information Administration & Sargent & Lundy, 2019)*

The net overnight capital cost, variable operations & maintenance (VOM) costs, and fixed operations & maintenance (FOM) costs shown for each technology are scaled according to project specific parameters. For example, the VOM costs are derived based on the amount of energy generated by each technology type, which depends on the plant's generation profile.

Due to the operational flexibility of NGCTs, additional plant characteristics such as minimum run time, seasonal startup costs, and seasonal heat rates are utilized to develop the operational logic for the NGCTs. These additional parameters are displayed in Appendix 4a and 4b.

## Experimental Design

The four hypothetical power plants are simulated in each of the five selected RTO regions.

As wind and PV plants are intermittent generation technologies, no operational logic is required as energy is generated based on the availability of natural resources. An hourly, location specific capacity factor (National Renewable Energy Laboratory, 2020), as seen in Figure 3, is applied to both wind and solar plants to determine the hourly energy generated.

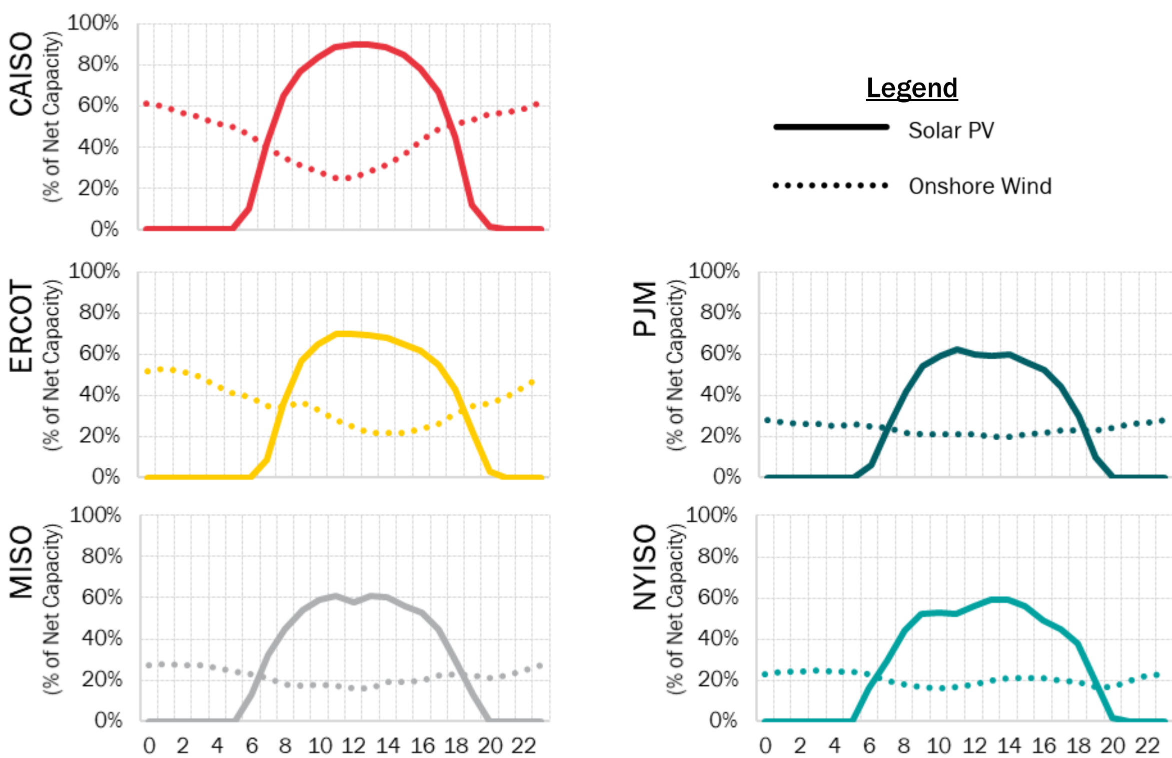


*Figure 3. Solar PV and wind hourly and location specific capacity factors for March 1st.*

As current wholesale power market design requires generators to offer bids at the marginal cost of generation, this study assumes both PV and wind plants offer 100% of the generating capacity into the day ahead market at the short run marginal cost, $0.00 per MWh. It is also assumed that the bids offered into the market are always accepted, with minimal basis and curtailment risk. While this may not reflect the reality of power markets due to the curtailment during times of high renewable penetration, assessing the effect of curtailment and basis is not the goal of this study and is therefore considered an acceptable assumption in the methodology. Due to the complex requirements and challenges for renewables to participate in capacity markets, it is assumed that renewables do not receive any revenue from capacity markets. They do, however, receive revenue from the sale of renewable energy credits (O'Shaughnessy, 2017).

SC and CC NGCT power plants, unlike PV and wind plants, require a dispatch logic as they are able to ramp up and down energy output depending on a predetermined objective. This study uses a dispatch logic that compares the price of natural gas to the DA LMP and determine, based on the plant's season heat rate and minimum run time, if the plant should operate during that hour or remine ideal till more favorable market conditions arise. The logic provided to the hypothetical power plant model is illustrated in the decision tree seen in Figure 4. In the tree, the variable $h$ represents each hour of the analysis. The hourly production costs were calculated using the formula seen below in Equation 1. The full Visual Basic for Applications (VBA) code developed can be found in Appendix 5.

$$Production\ Cost(h) = Seasonal\ Heat\ Rate(h) * Plant\ Capacity(h) * Cost\ of\ NG(h) \qquad \text{Eq. 1}$$

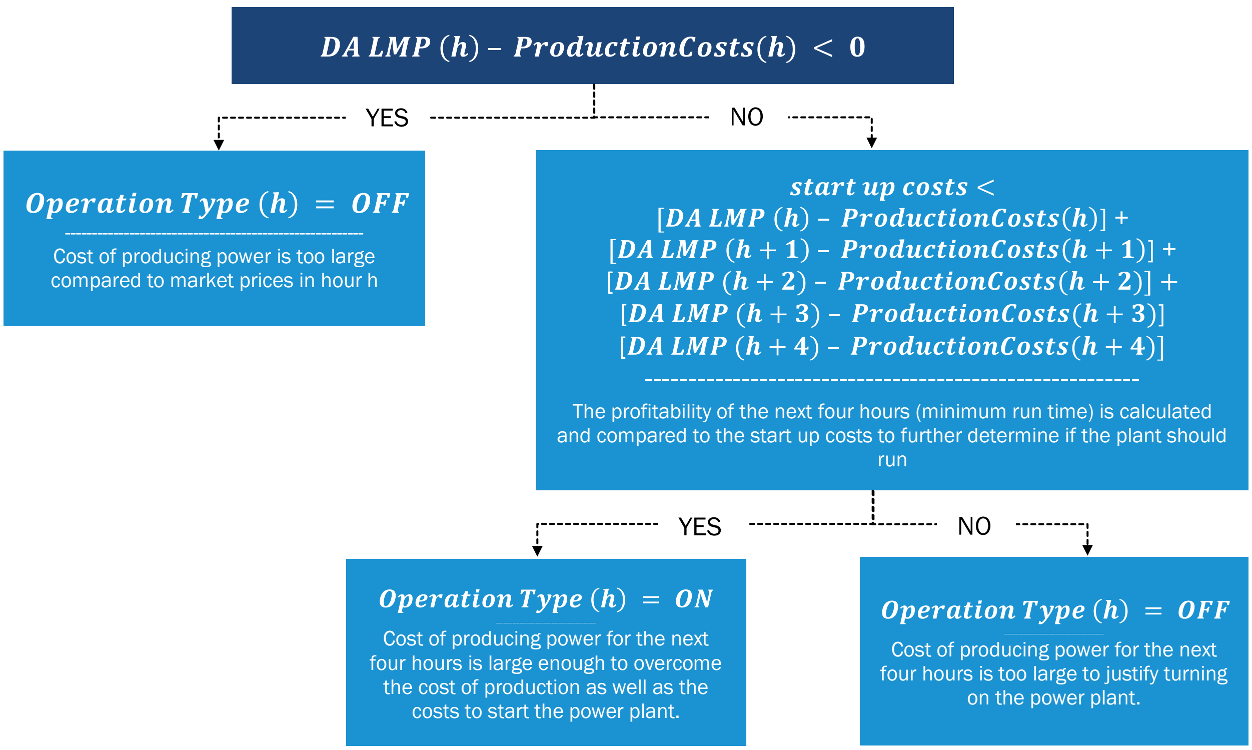


*Figure 4. Dispatch decision tree for both NGCT SC and CC power plants.*

Figure 5 illustrates the operational profile of a hypothetical NGCT CC in PJM based on this dispatch logic. The capacity factor of the plant is plotted in red on the left y-axis, which indicates the level at which the power plant is producing energy. The DA LMP and cost of production are plotted on the right y-axis, using a logarithmic scale for improved visualization. It can be seen that when the cost of production gets close to or surpasses the DA LMP, the capacity factor is reduced, representing a time when the market price of electricty is not high enough to warrant production.

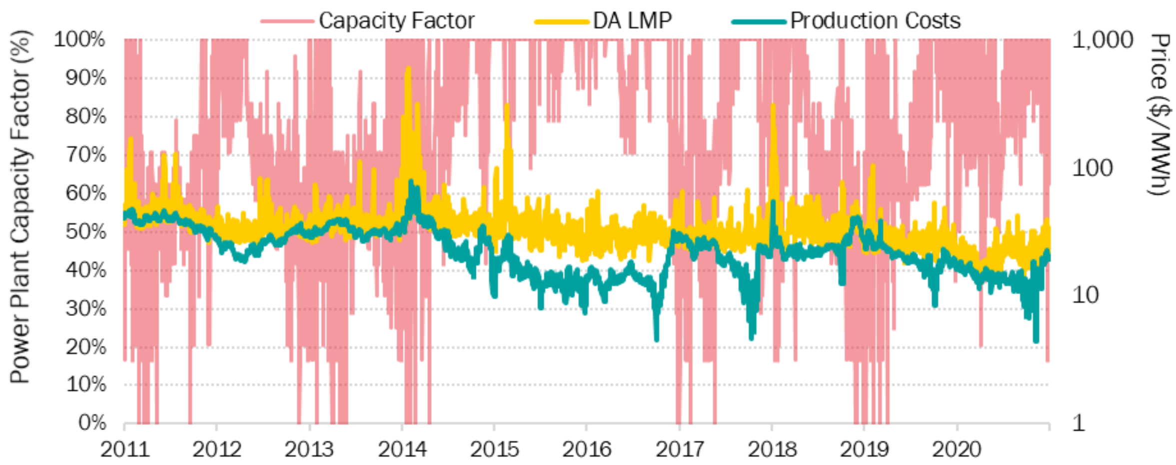


*Figure 5. Operating profile of hypothetical 400MWdc NGCT CC Power Plant in PJM*

Additionally, both CC and SC plants are assumed to clear capacity markets and receive revenue based on their full capacity. CC and SC plants do not earn revenue from renewable energy credits.

Once the operational model of the hypothetic power plants was developed, an annual income statement was created for each generation type in each grid region in order to assess its profitability. A sample income statement for a NGCT CC in PJM is provided in Appendix 6. The financial statements are adjusted for inflation to $USD2021 according to the index provided in Appendix 7 (World Bank, 2021). In order to compare profitability across technologies, an annualized capital cost recovery (ACCR) metric was developed. The ACCR, shown in Equation 2, represents the annual earnings before interest, tax, depreciation, and amortization (EBITDA) as a percentage of the annualized capital costs. The plants annualized capital costs are calculated similar to that of an annuity payment, in that it represents the "fraction of the total installed cost (TIC) that must be set aside each year to retire capital costs" (Blumsack, 2018). In order to determine this annual amount, the TIC is multiplied by a capital recovery factor (CRF). The equation used for CRF is displayed in Equation 3.

$$ACCR = \frac{EBITDA}{TIC * CRF} \qquad \text{Eq. 2}$$

$$CRF = \frac{r(1+r)^T}{(1+r)^T - 1} \qquad \text{Eq. 3}$$

Where…

$$r = discount\ rate$$
$$T = economic\ life\ span\ of\ power\ plant$$

Special care was given when selecting a discount rate as changes in the discount rate have a large effect on future cash flows. Using a report by JPMorgan's Public Power Group, which evaluated the weighted average cost of capital (WACC) for various merchant power project using project finance, a discount rate of 12.2% was selected (Krellenstein, 2004).

## Results

The results of the analysis suggest that power plants, renewable and natural gas alike, are unable to recover capital costs and generate adequate returns from wholesale power markets. The results also indicate that the profitability of a power plant is highly depending on market conditions and varies greatly from year to year. The results from the analysis are provided in Figures 6a – 6d.

Figures 6a - 6d are a timeseries line chart of the ACCR. When the ACCR is equal to or above 100%, the power plant was able to generate an annual EBITDA that sufficiently covers the annual fraction of the project's capital cost. Alternatively, if the ACCR is below 100%, the plant is unable to cover its annualized capital cost. Accompanying the time series graphs is a table which shows the average ACCR over the 10-year period.

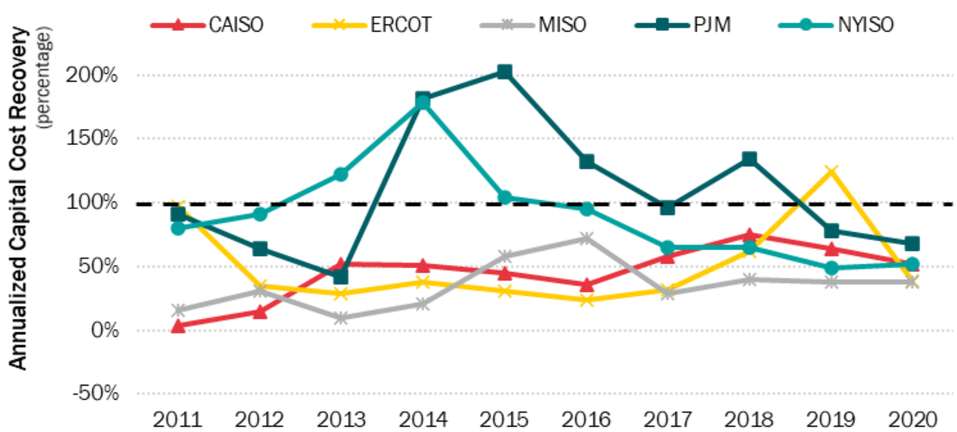


*Figure 6a: EBITDA as a function of annualized capital costs - NGCT CC*

| Region | Average ACCR |
|---|---|
| CAISO | 45% |
| ERCOT | 51% |
| MISO | 35% |
| PJM | 109% |
| NYISO | 90% |

*Table 3a:10-year ACCR average - NGCT CC*

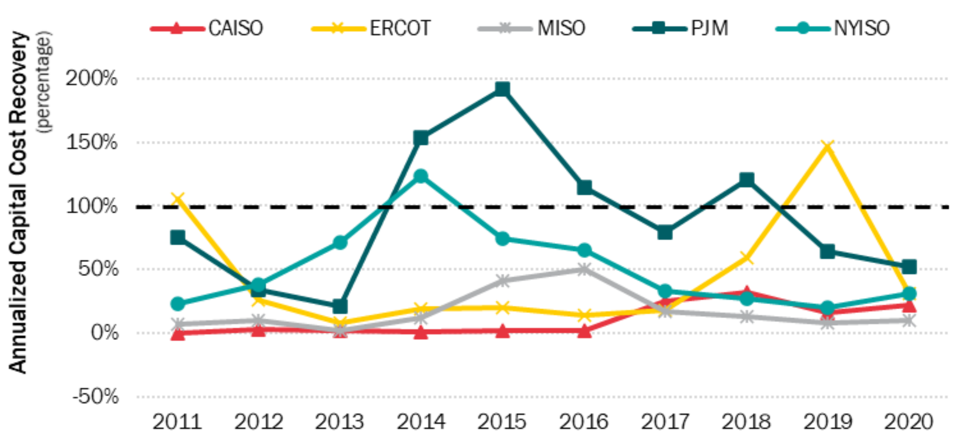


*Figure 6b: EBITDA as a function of annualized capital costs - NGCT SC*

| Region | Average ACCR |
|---|---|
| CAISO | 10% |
| ERCOT | 45% |
| MISO | 17% |
| PJM | 91% |
| NYISO | 51% |

*Table 3b:10-year ACCR average - NGCT SC*

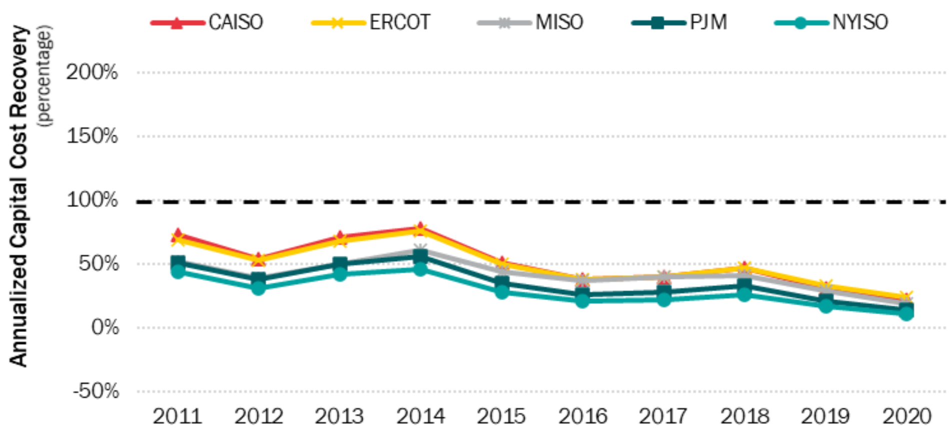

Figure 6c: EBITDA as a function of annualized capital costs - Solar PV

| Region | Average ACCR |
|---|---|
| CAISO | 51% |
| ERCOT | 50% |
| MISO | 41% |
| PJM | 35% |
| NYISO | 29% |

Table 3c:10-year ACCR average – Solar PV

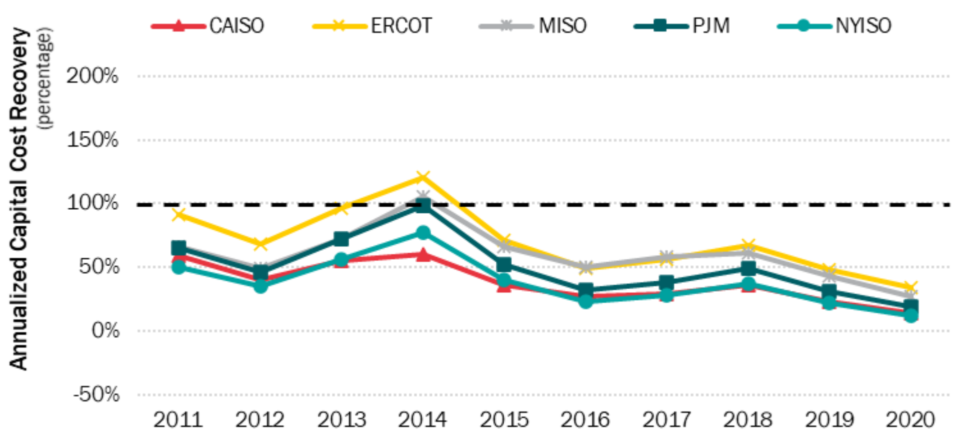

Figure 6d: EBITDA as a function of annualized capital costs - Onshore Wind

| Region | Average ACCR |
|---|---|
| CAISO | 38% |
| ERCOT | 71% |
| MISO | 60% |
| PJM | 52% |
| NYISO | 38% |

Table 3d:10-year ACCR average – Onshore Wind

The results from Figure 6a show the ACCR of a NGCT CC power plant in the five RTO regions. In CAISO and MISO, the plant is never able to recover its annualized capital costs over the analysis period. In ERCOT, the plant only recovers its annualized capital costs in 2019, during which the ACCR increased above 100% to 127%. In PJM and NYISO, the ACCR bounces above and below 100%. In Table 3a, it becomes evident that on average, only in PJM is the NGCT CC plant able to yield an average ACCR above 100%.

A similar scenario is evident in Figure 6b, which shows the results of a NGCT SC power plant. The hypothetical plant is able to yield ACCRs greater than 100% in only a few years in PJM, NYISO and ERCOT. When viewing the average ACCRs in Table 3b, it is apparent that a NGCT SC plant is not able to recover its annualized capital cost in any of the grids.

Figures 6c and 6d, PV and wind respectively, highlight the inability of the renewable generators plants to recover their respective annualized capital cost year over year, with the one exception of a wind power plant in ERCOT, where in 2014, the ACCR peaks at 119%. The average ACCRs highlight that over the course of the 10-year analysis period, the average ACCRs remain well below 100%, falling as low as 29% for PV projects in NYISO.

While the result for each technology type leads to a similar conclusion, there are differences between the extend of the profitability between renewable and natural gas plants in the different grid regions. As seen in Figure 7, in PJM and NYISO, both SC and CC plants have favorable economics compared to wind and solar projects, while in ERCOT, wind and solar compete more closely with natural gas plants. Further analysis is required to determine the causation of these findings. It is, however, hypothesized that the difference in profitability between technologies and grid regions can be explained through differences in natural resources, renewable energy credits, and energy market design, such as capacity markets and energy price caps (Moore & Giannetti, 2021).

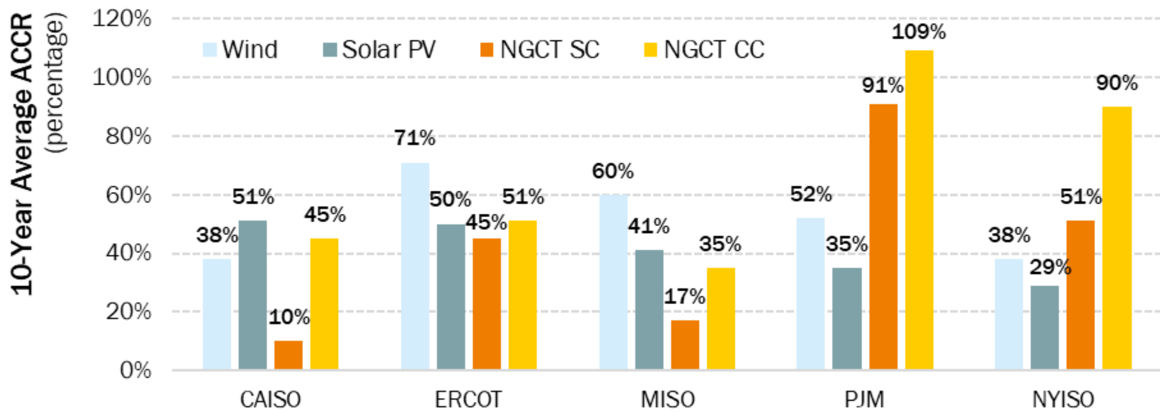


*Figure 7: 10-year average ACCR for each grid and technology type.*

A large component of this analysis is the use of the capital recovery factor (CRF) shown in Equation 3, which involves a discount rate. Determining an appropriate discount rate is highly debated due to the various derivations of an appropriate rate and its large impact on future cash flows. While evaluating the legitimacy of the selected discount rate is not the goal of this study, in order to develop robust conclusions and understand the extent to which these conclusions hold true, a sensitivity analysis of the effect of discount rate on average ACCR is conducted. The results of this sensitivity analysis can be seen in Figure 8a – 8d.

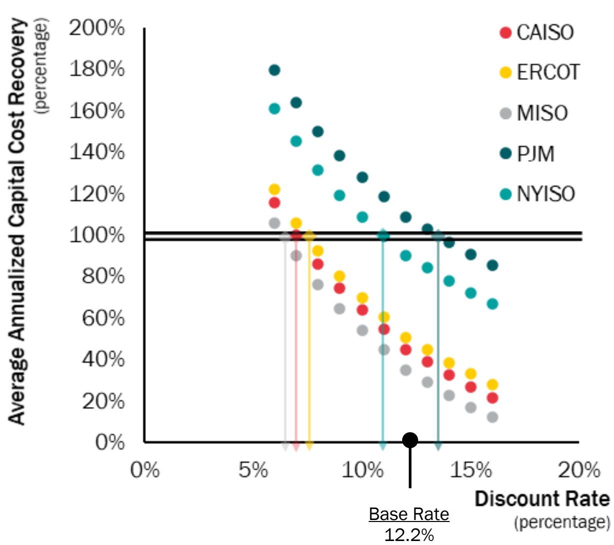


*Figure 8a: NGCT CC Discount Rate Sensitivity*

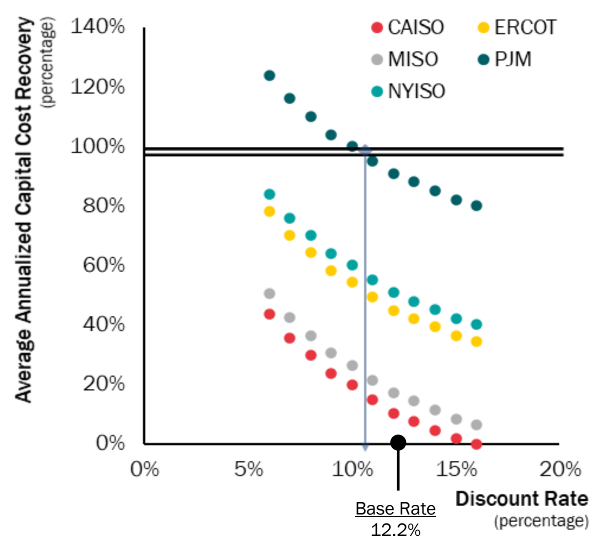


*Figure 8b: NGCT SC Discount Rate Sensitivity*

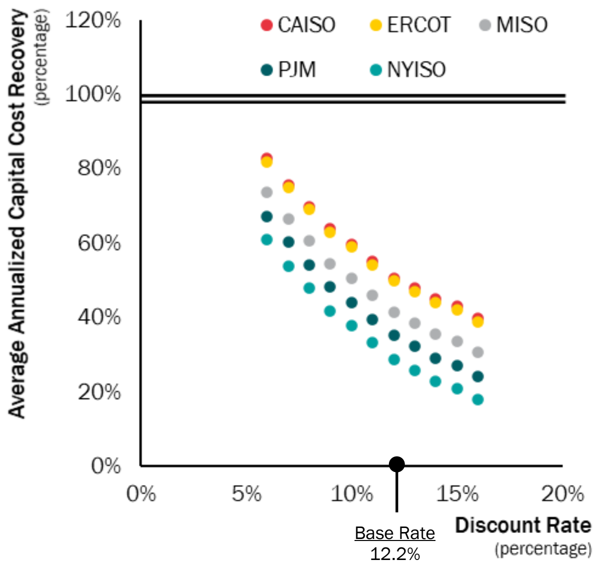


*Figure 8c: Solar PV Discount Rate Sensitivity*

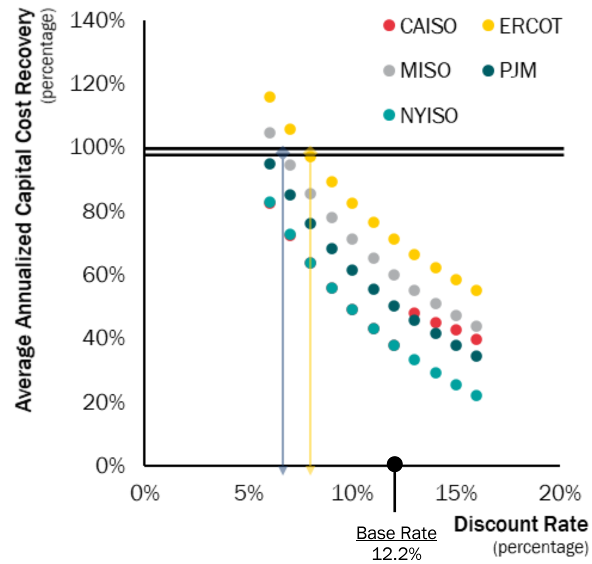


*Figure 8d: Wind PV Discount Rate Sensitivity*

Plotted on the x-axis of the graph is the discount rate and plotted on the y-axis represents the 10-year average ACCR. The results from this sensitivity analysis further support the initial claim that power plants endure systematic challenges in delivering desirable financial returns in fully merchant offtake structures. When interpreting the sensitivity analysis, it is worth reiterating that a lower discount rate results in a higher present value due to less discounting of future cash flows. In these sensitivity results, a focus is placed on understanding how low the discount rate can be for projects to attain 100% ACCR, the threshold for a viable project.

Figure 8a shows that a NGCT CC plant in PJM will reach 100% average ACCR at a discount rate of 14.2%, while that same plant in MISO will reach 100% average ACCR at 6.3%. Figure 8b shows that a SC plant reaches 100% average ACCR at 11.2% in PJM, while all other grid regions remain below 100% for the extend of the sensitivity. A solar PV plant, Figure 8c, remains below 100% average ACCR in all tested grid regions. A wind plant, Figure 8d, in ERCOT and MISO yields an average ACCR above 100% at a discount rate of 7.9% and 6.1% respectively while all other grid regions do not yield ACCRs greater than 100% for the extend of the sensitivity.

## Discussion and Conclusions

This study asked two main questions to evaluate the ability of power generation technologies to achieve an adequate return on investment in deregulated wholesale power markets. First, do exisiting power markets incentivize merchant generates to invest in and operate generating facilities? And second, to what extend do current market designs promote renewable power generation?

The results of this study suggest that power plants with full merchant exposure have small profit margins and are largely unable to recover capital investments. Across all grid regions and technology types, with the exception of a NGCT CC plant in PJM, the hypothetical power plants studied were unable to recover their annualized capital costs during the analysis period.

These results are, in part, a consequence of the way in which deregulated power markets are designed. Current wholesale power markets require generators to offer energy prices at the plant's short run marginal cost of generation (Cleary & Palmer, 2020). When the energy market clears at a plant's short run marginal cost, the plant is only able to covers its marginal cost of generation, not the cost of investment. Capacity markets were developed with the hope of providing the money to attract investment, famously known as the "missing money" (Joskow, 2019). However, due to the challenges of participating in the capacity market and its ability to achieve an adequate clearing price, offsetting the missing money has been challenging and in large, unsuccessful (O'Sullivan et al., 2020).

Looking into the future, as the share of power generation becomes progressively renewable, wholesale power markets will face increasingly unfavorable investment prospects. Imagine a power grid in which 100% of energy demand is met with renewable generation; because renewables have zero marginal generation costs, the market clearing price will continuously be set at $0 per MWh, leaving no revenue to be made in the energy market (Gifford et al., 2017). Figure 9 plots the percent of hours each year that the market clearing price was below $2/MWh. Despite a few outliers, namely CAISO during the 2011 Southwest blackout, a gradual increase in the frequency of low energy prices can be seen and is expected to increase as the proliferation of renewables increases.

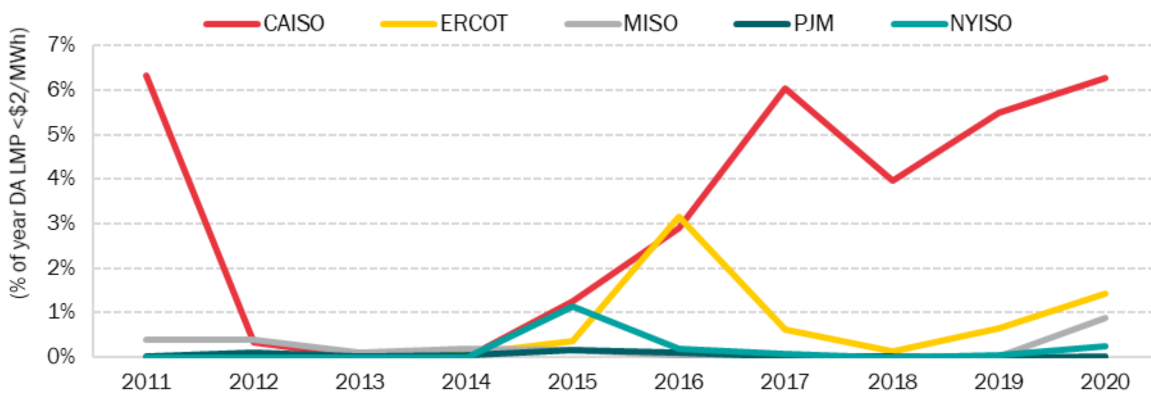


*Figure 9. Percent of the year the DA LMP was less than $2/MWh*

In closing, the accelerated pace at which the power grid must decarbonize in order to avoid the harshest impacts of climate change is undeniable (Bruckner et al., 2017). In turn developing robust market guidelines that holistically account for the changing power grid is pivotal to achieving a fully decarbonized power grid. The results of this paper hope to draw attention to the economic realities of merchant generators, highlighting the challenges to promote investments in reliable, carbon free power generation.

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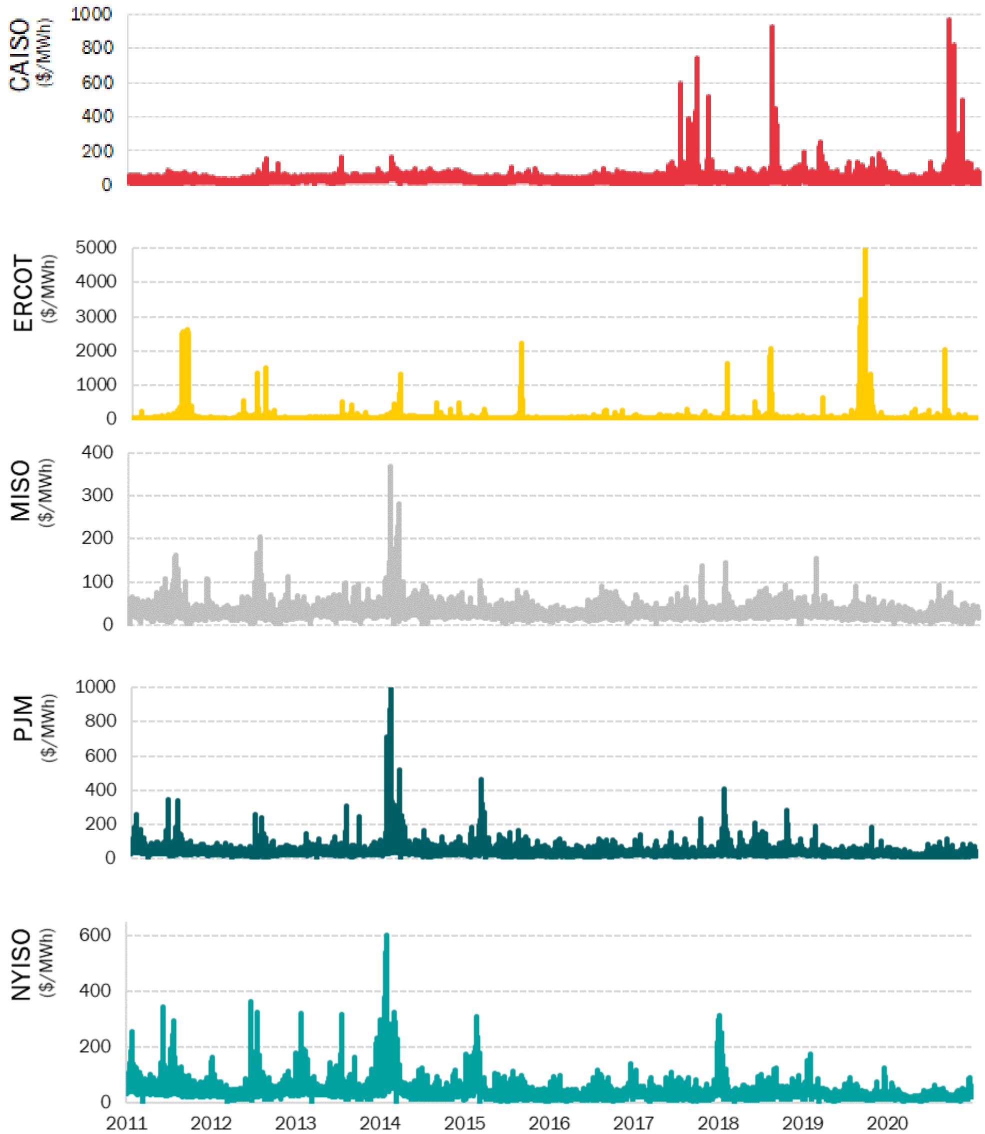
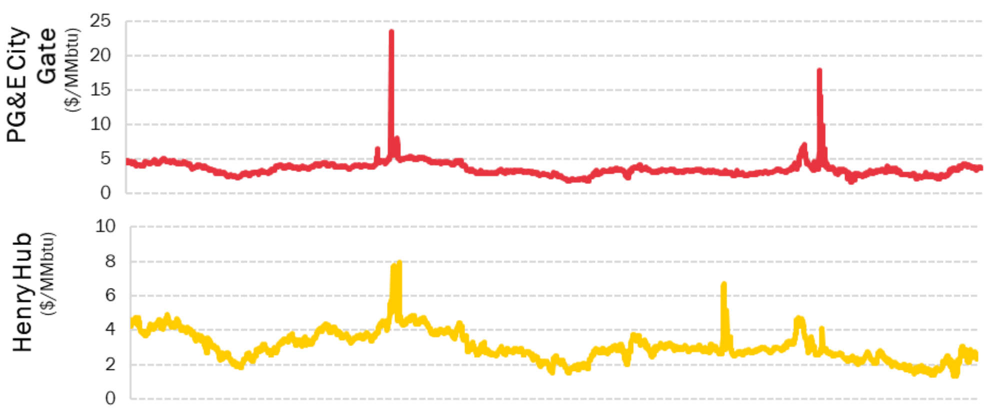
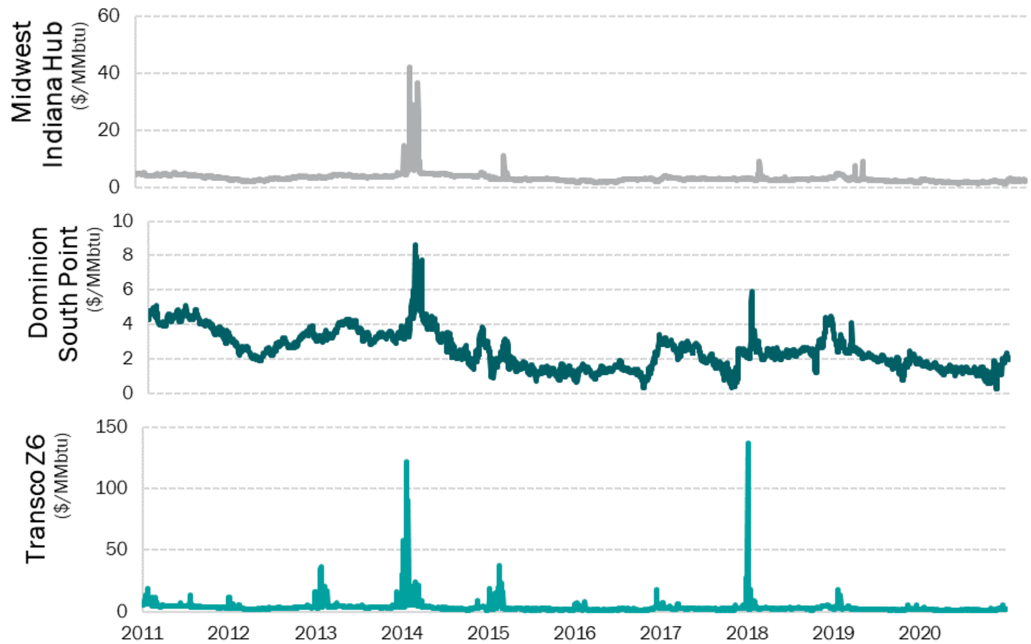
## Appendix

### Appendix 1 – Day Ahead Locational Marginal Price

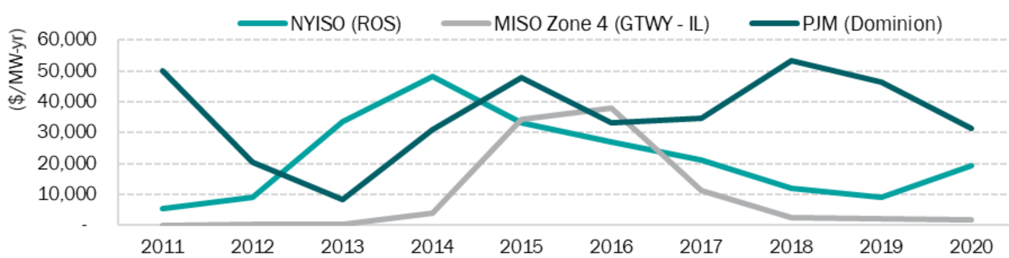



### Appendix 2 – Natural Gas Prices



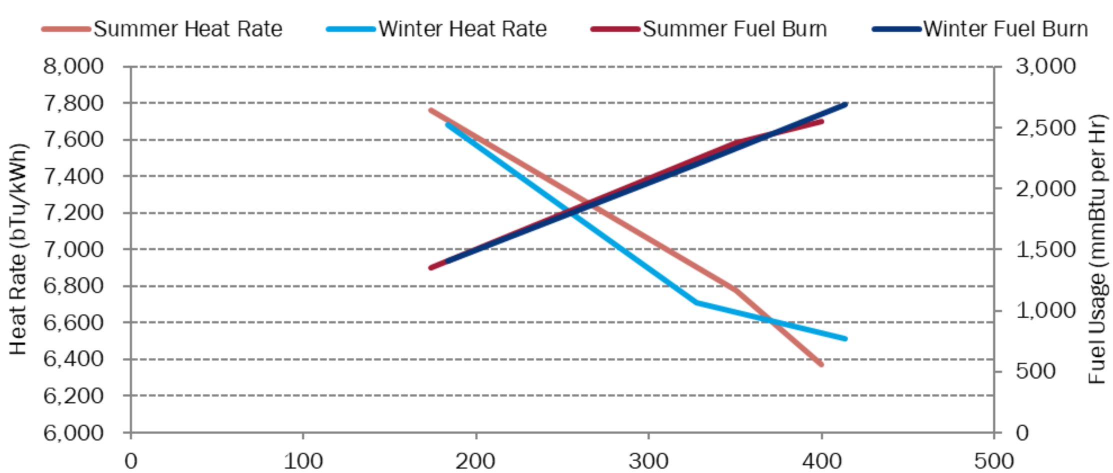



## Appendix 3 - Capacity Prices



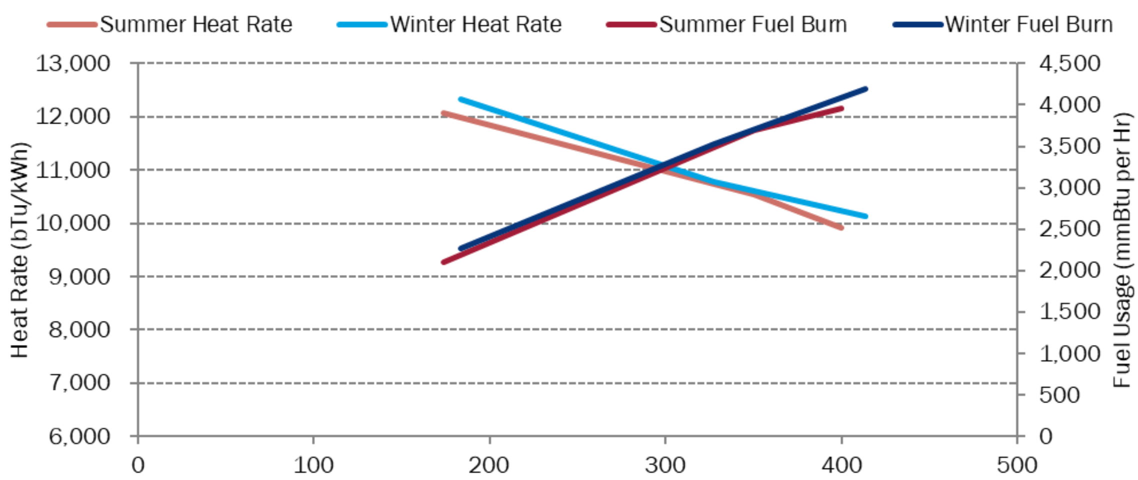

## Appendix 4a – Additional NGCT CC Power Plant Characteristics

| Condition | Duct Fire | MW Output | | Δ MW | | Heat Rate (Btu/kWh) | | Fuel Burn (mmBtu per Hour) | | Δ Fuel Burn (mmBtu per Hour) | | Marginal Heat Rate (Btu/kWh) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Summer | Winter | Summer | Winter | Summer | Winter | Summer | Winter | Summer | Winter | Summer | Winter |
| Full Load + Duct Fire | On | 400.0 | 413.3 | 50.0 | 85.8 | 6,370 | 6,514 | 2,548.0 | 2,691.9 | 175 | 494 | 3,507 | 5,756 |
| 1 CTs @ 100% | Off | 350.0 | 327.5 | 176.0 | 144.1 | 6,779 | 6,712 | 2,372.7 | 2,198.2 | 1,022 | 789 | 5,809 | 5,476 |
| 1 CTs @ 50% | Off | 174.0 | 183.4 | | | 7,760 | 7,683 | 1,350.2 | 1,409.1 | | | | |



## Appendix 4b – Additional NGCT SC Power Plant Characteristics

| Condition | Duct Fire | MW Output | | Δ MW | | Heat Rate (Btu/kWh) | | Fuel Burn (mmBtu per Hour) | | Δ Fuel Burn (mmBtu per Hour) | | Marginal Heat Rate (Btu/kWh) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Summer | Winter | Summer | Winter | Summer | Winter | Summer | Winter | Summer | Winter | Summer | Winter |
| Full Load + Duct Fire | On | 400.0 | 413.3 | 50.0 | 85.8 | 9,905 | 10,128 | 3,962.0 | 4,185.8 | 273 | 656 | 5,453 | 7,645 |
| 1 CTs @ 100% | Off | 350.0 | 327.5 | 176.0 | 144.1 | 10,541 | 10,779 | 3,689.3 | 3,530.0 | 1,590 | 1,267 | 9,033 | 8,793 |
| 1 CTs @ 50% | Off | 174.0 | 183.4 | | | 12,066 | 12,338 | 2,099.5 | 2,262.8 | | | | |




## Appendix 5 – VBA code for power plant logic

```
Sub GetOpTypeZ()
    Application.ScreenUpdating = False
    Application.Calculation = xlCalculationManual
    CurBook = ActiveWorkbook.Name
    'PrTableChoice = Range("PrTableChoice")
    'If PrTableChoice = "SRMC" Then
     '   PriceTable = Range("PriceTable")
    'Else
        PriceTable = Range("PriceTableAllIn")
    'End If
    NoYr = Range("PriceTableAllIn").Columns.Count
    NoDays = Range("PriceTableAllIn").Rows.Count
    Capacity = Range("Capacity")
    ProdCosts = Range("ProdCosts")
    StartCosts = Range("StartCosts")
    DFMargCosts = Range("DFMargCost")

    InitYear = Range("InitYear")
    FLoadRef = 4
    MLoadRef = 1
    C1LoadRef = 2
    M2LoadRef = 3

    CumHrs = Array(0, 744, 1440, 2184, 2904, 3648, 4368, 5112, 5856, 6576, 7320, 8040, 8784)
    MnthHrs = Array(744, 672, 744, 720, 744, 720, 744, 744, 720, 744, 720, 744)
    LeapHrs = Array(744, 696, 744, 720, 744, 720, 744, 744, 720, 744, 720, 744)


    For i = InitYear To InitYear + 20
        If i Mod 4 = 0 Then NoLeapYr = NoLeapYr + 1
    Next i
    NoHrs = NoYr * 8760 + NoLeapYr * 24

    ReDim PrStrip(NoHrs, 2), OpType(NoHrs), OpTable(NoDays, NoYr)
    ReDim BlockProfit(NoHrs, 3)
    H = 1                                      'tracks hours
    M = 1                                      'tracks month
    D = 1
    For i = 1 To NoYr                          'loop through each year
        YrRef = (i - 1) * 12
        If (InitYear - 1 + i) Mod 4 = 0 Then   'find if year is leap year or not
            MnHrs = LeapHrs
        Else
            MnHrs = MnthHrs
```

```
        End If
        For j = 1 To 12                         'loop through each month
            For k = 1 To MnHrs(j)               'loop through each hour of month
                PrStrip(H, 1) = D       'represents month that hour is in(total months = 12*20) - change to day
instead of month
                PrStrip(H, 2) = PriceTable(CumHrs(j) + k, i)    'copies price at that hour from AllinPrice table
                For l = 1 To 3                  'calculate profit for each CT and Duct Fire
                    BlockProfit(H, l) = (PrStrip(H, 2) - ProdCosts(PrStrip(H, 1), l)) * Capacity(PrStrip(H, 1),
l) 'profit for that hours is (price-prod cost of month)*capacity of month
                Next l          'possible change is to use hourly capacity instead of monthly
                If H Mod 24 = 0 Then D = D + 1
                H = H + 1
                If H = 87673 Then GoTo Out:    'changed H to extend model timeframe <NOTE AR: THIS NEEDS CHANGING
IF ENERGY DATA TIME LENGTH CHANGES>
            Next k
            M = M + 1
        Next j
    Next i
Out:
    H = 1
    For i = 1 To NoYr
        If (InitYear - 1 + i) Mod 4 = 0 Then
            MnHrs = LeapHrs
            CumHrs = CumHrsLeap
            Days = 366
        Else
            MnHrs = MnthHrs
            CumHrs = CumHrs
            Days = 365
        End If

        For j = 1 To 12
            For k = 1 To MnHrs(j)
                If PrStrip(H, 2) - ProdCosts(PrStrip(H, 1), 2) < 0 Then 'loops to find if unit is operating or
not. if not assigns 0
                    OpType(H) = 0
                    H = H + 1
                Else
                    If H = 1 Then
                        GoTo Calc:
                    End If
                    If OpType(H - 1) = 3 Then
                        OpType(H) = 3
                        H = H + 1
                    Else
Calc:
                        CumProfit = 0
                        For l = H To H + 4
                            Margin = (PrStrip(l, 2) - ProdCosts(PrStrip(l, 1), 2)) * Capacity(PrStrip(l, 1), 2)
' calculates profit margin
                            CumProfit = CumProfit + Margin   ' adds to cumilative profit
                        Next l
                        If CumProfit > StartCosts(PrStrip(H, 1), 1) Then
                            For l = H To H + 4
                                OpType(l) = 3
                            Next l
                        Else
                            For l = H To H + 4
                                OpType(l) = 0
                            Next l
                        End If
                        k = k + 3
                        H = H + 4
                    End If
                End If
                If H = 87673 Then GoTo Copy:   'changed H to extend model timeframe <NOTE AR: THIS NEEDS CHANGING
IF ENERGY DATA TIME LENGTH CHANGES>
                Next k
            Next j
            'MsgBox "Year"
        Next i
Copy:
        H = 1
    THrs = 0
    For i = 1 To NoYr 'loop each year
        If (InitYear - 1 + i) Mod 4 = 0 Then
            MnHrs = LeapHrs
        Else
            MnHrs = MnthHrs
        End If
```

```
        For j = 1 To 12 'month loop
            If j = 1 Then
                CumHrs = 0
            ElseIf j = 3 And (InitYear - 1 + i) Mod 4 <> 0 Then
                CumHrs = CumHrs + MnHrs(j - 1) + 24 'adjust down 24 hours for non leap years
            Else
                CumHrs = CumHrs + MnHrs(j - 1)
            End If
            For k = 1 To MnHrs(j) 'hour loop
                OpTable(CumHrs + k, i) = OpType(H)
                H = H + 1
            Next k
        Next j
    Next i
    Range("OpType") = OpTable
    Application.ScreenUpdating = True
    Application.Calculation = xlCalculationAutomatic
    aaa = MsgBox("Done", vbOKOnly)
End Sub
```

## Appendix 6 – Sample Income Statement for NGCT CC in PJM

| EBITDA ($000) | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Revenues** | | | | | | | | | | |
| **Capacity** | 20,304 | 8,252 | 3,419 | 12,617 | 19,442 | 13,502 | 14,048 | 21,677 | 18,846 | 12,845 |
| **Energy** | 112,906 | 98,372 | 96,216 | 170,318 | 137,465 | 105,221 | 96,002 | 115,094 | 80,723 | 70,531 |
| **Renewable Energy Credit** | - | - | - | - | - | - | - | - | - | - |
| **Total** | 133,210 | 106,624 | 99,634 | 182,936 | 156,907 | 118,723 | 110,050 | 136,771 | 99,569 | 83,376 |
| | | | | | | | | | | |
| **Production Expenses** | | | | | | | | | | |
| **Fuel** | 78,090 | 64,263 | 68,483 | 81,853 | 45,670 | 41,961 | 51,143 | 59,105 | 49,308 | 37,932 |
| **Variable O&M** | 5,327 | 6,041 | 5,664 | 6,214 | 6,197 | 6,269 | 6,369 | 6,312 | 6,650 | 7,025 |
| **Emissions** | - | - | - | - | - | - | - | - | - | - |
| **Total** | 83,418 | 70,303 | 74,147 | 88,067 | 51,867 | 48,230 | 57,512 | 65,416 | 55,958 | 44,957 |
| | | | | | | | | | | |
| **Dispatch Margin (Energy - Tot Prod Exp.** | 29,488 | 28,068 | 22,068 | 82,251 | 85,598 | 56,991 | 38,490 | 49,678 | 24,765 | 25,574 |
| **Dispatch Margin with REC Revenue** | 29,488 | 28,068 | 22,068 | 82,251 | 85,598 | 56,991 | 38,490 | 49,678 | 24,765 | 25,574 |
| **Operating Margin** | 49,792 | 36,320 | 25,487 | 94,869 | 105,040 | 70,493 | 52,538 | 71,354 | 43,611 | 38,418 |
| | | | | | | | | | | |
| **Fixed O&M** | 4,880 | 4,880 | 4,880 | 4,880 | 4,880 | 4,880 | 4,880 | 4,880 | 4,880 | 4,880 |
| **EBITDA** | 44,912 | 31,440 | 20,607 | 89,989 | 100,160 | 65,613 | 47,658 | 66,474 | 38,731 | 33,538 |

## Appendix 7 Inflation index