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Performance of Generating Plant: Managing the Changes

World Energy Council 2008

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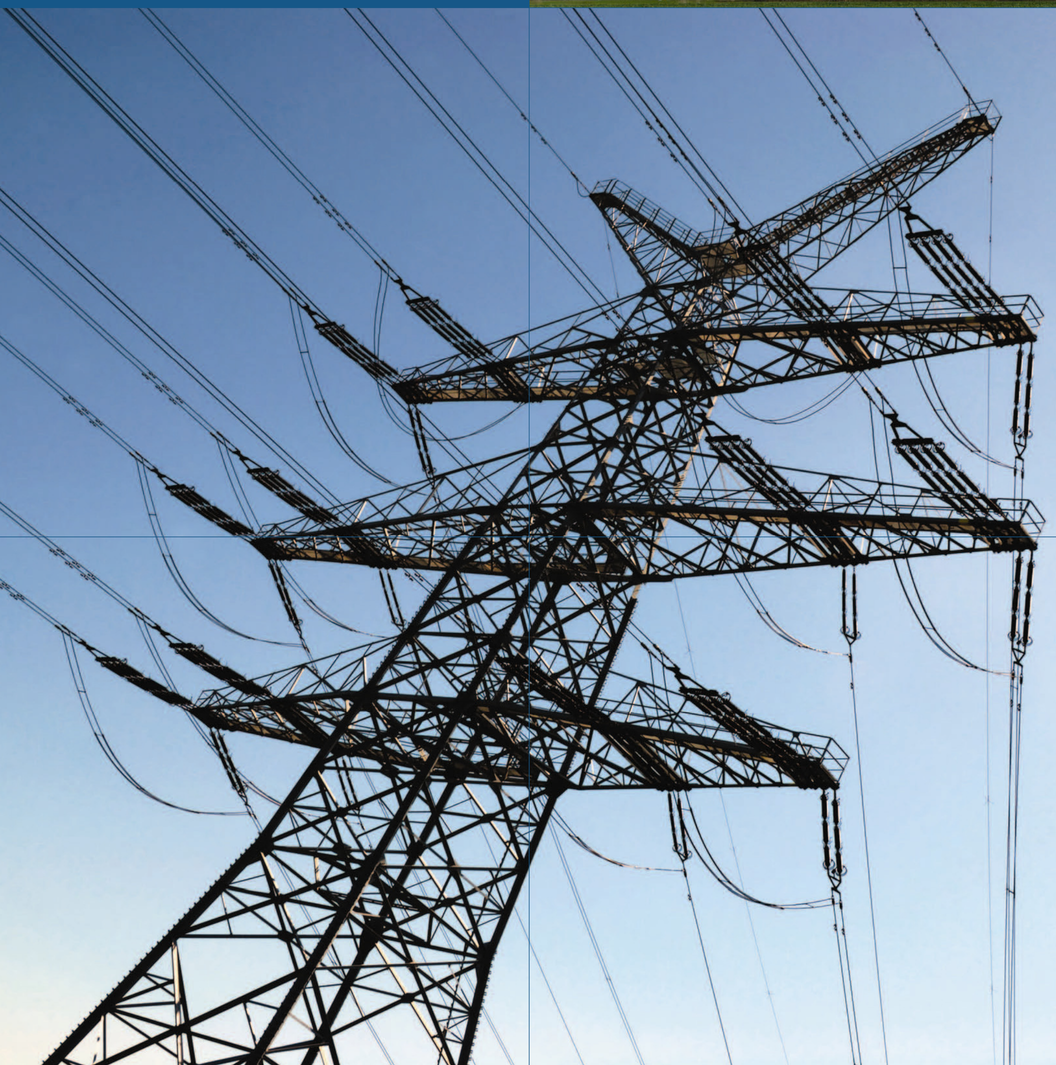

Performance of Generating Plant

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International Availability Data Exchange

Contents

Work Group 1

International Availability Data Exchange for Thermal Generating Plant

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1. Introduction

As of 2007, the global electric supply industry (ESI) continues to see significant change. Worldwide, the ESI continues to face enormous change and pressures to provide reliable electric supply at reasonable cost. Yet, regional differences have yielded different strategies, activities, and ultimately, different goals/priorities for generation assets. This is largely due to the wide variety of situations that co-exist in today's global ESI.

One of the key goals of the Performance of Generating Plant (PGP) committee is to identify processes, tools, and/or techniques for measuring performance. Via such processes, it is possible for generators to benchmark the performance of their units to that of others and to identify "best of class" performance standards for its peer group. Traditional measures for plant reliability/availability such as UCF (unit capability factor), UCLF (unplanned capability loss factor) only tell part of the story. The reality is that mixed regulatory, ownership and market perspectives corresponds to mixed goals, objectives, and priorities for generation entities. Varying business models, varying risk profiles, and different "obligations to serve" all further complicate the issue.

- What are the key metrics? Technical? Commercial? Environmental? Or even sustainability?

Our committee's work suggests that all play a key role in measuring and improving plant performance! In the 2004-2007, significant changes to the committee's charter or terms of reference were made to address these needs; in addition, PGP has continued its evolution of "data analysis" and statistics to include other factors/goals sets. Specifically,

- Data collection and analysis has been extended to include renewables.
- Data analysis technique and processes have been developed to better understand how to compare performance of generators across different markets, environmental drivers, etc.
- Data collection systems and tools being deployed are capable of capturing broad range of performance data necessary to evaluate distribution of performance indicators (vs. simply overall population averages) to better understand what represents "best of class" performance.

As the global power market continue to "evolve" worldwide, it is clear that performance is becoming increasingly important. However, areas of concern and means for measuring or reporting performance are from clear or consistent. In fact, the situation is quite fragmented:

- The fact that power markets and regulated framework co-exist results in what is essentially a lack of standards or practices for measuring performance. As a result, large variations in structure and focus exist within the various markets globally.

- The definition or scope of performance also varies widely and can include range of issues including reliability/availability, capacity, efficiency, cost-effectiveness, environmental performance, and market performance (e.g., commercial availability, option value/risk profile, etc.)
- Reluctance to support collection and analysis of performance data continues to be an issue due to competitive postures, variations in markets, technology, and inclusion of costs into the mix.
- New drivers geared toward profitability, cost control, environmental stewardship and market economics are shifting the focus away from traditional measures of technical excellence such as availability, reliability, forced outage rate, and heat rate toward the bottom line.

Further, in the future, shifts in generation mix will impact picture of reliability and performance as different technologies are introduced for either environmental control or for power generation. This will likely lead to a situation where generation mix will simultaneously be impacted by further environmental controls applied to aging plant at the same time as different technologies (e.g., renewables, IGCC, Coal with carbon capture) are initially deployed.

And, as the issue of performance becomes increasingly complex, the ability to “measure” and analyze performance is even more challenging! There is no clear “right” answer on how to address this issue; different entities, different facilities, different markets, and different obligations will yield different needs. It should not be surprising, therefore, that the ESI is somewhat at the crossroad both in terms of how it measures itself but also what data or information is necessary to support such measures.

This paper explores the specific work activities of 2004-2007 to extend traditional analysis and benchmarking frameworks. It is divided into two major topics.

Topic 1: Overview of Current Electric Supply Industry Issues/Trends.

Our discussion focuses on how needs/issues associated with the industry are impacted by major drivers such as deregulation/privatization, increased environmental sensitivities, nationalistic priorities to secure energy supply, and deployment of non-traditional technologies.

- *Section 2: Industry Outlook*. This section focuses on key drivers for ESI worldwide and the implications on performance goals, priorities, measures, and value of performance data.
- *Section 3: Implications for the Future*. This section discusses how current and future issues shaping the industry are expected to shape/define the ongoing work of WEC and others to provide means to support performance improvement and energy sustainability.

Topic 2: Technical Methods/Tools To Evaluate Performance In Today's ESI

Our discussion focuses on how to address performance in the context of the current situation and introduces a new tool developed by the WEC to "bridge" traditional and non-traditional performance measures.

- *Section 4: Leveraging Performance Data*. This section introduces PGP's strategy and work to date to evaluate performance in the context of both traditional and "commercial" measures. Given the inconsistent regulatory and market frameworks, the PGP committee feels that such a bridge could be a key to better understanding performance trends and opportunities for improvement. Several example case studies are used to illustrate. *Section 5: Overview of the PGP Technical & Commercial Performance Model*. This section provides a high-level description of the Excel-based Technical & Commercial Performance Model; this introduction provides a flow chart outlining the major inputs/outputs/models and a high level description of its key elements.
- *Section 6: Conclusions*. This section summarizes the conclusions about our work during 2004-2007 and provides a brief perspective on where we see our work programme progressing in the 2008-2011 triennial period.

1.1 2004-2007 PGP Terms of Reference

The Committee will continue promoting the international exchange of data and information on generating plant performance to facilitate the most effective use of generation assets and energy resources worldwide. Building on the findings of Committee's extensive research and analysis of the factors determining the performance of generating plant, particular emphasis will be placed on communications and a wider deployment of the recommendations and methodologies for improvement of power plant availability developed or identified by the Committee. The second phase in the development of WEC's generating plant performance indicators database will be completed. Annual power plant availability statistics collection and direct entry of data into the WEC database by participating companies and organisations will be encouraged.

Market forces and widely different market structures, differing degrees of deregulation and private participation, different technologies, varying environmental standards, etc. have greatly impacted the way the electricity sector operates and created a need to supplement traditional performance indicators and group statistics. Hence, advances in "form" or focus of indices or performance measures are needed to more closely align such measures to the mission of the power generator. Similarly, new strategies, greater collaboration within the industry, and new tools are required to make it possible to collect, analyse, and leverage new performance measures.

The following activities are included in the Committee work programme:

Work Group 1 (WG1): International Data Exchange, Workshops and Communications

WG1's primary focus is to analyse the best ways to measure, evaluate, and apply power plant performance and availability data to promote plant performance improvements worldwide. The activities include identification of new performance measures. This work would be carried out in collaboration with other interested organisations. Various communication vehicles would be implemented to enhance the visibility of the mission and seek out cooperation opportunities, including workshops, white papers, joint technical conference sessions, etc. Case studies or other examples of how new, more commercial or market oriented performance measures have been applied to advance performance within the electricity sector will be published on PGP's home page on GEIS.

Work Group 2 (WG2): Power Plant Availability Statistics

WG2 main task is to facilitate the collection and input on an annual basis of power plant performance data (unit-by-unit and aggregated data) into the WEC PGP database. The statistics will be collected for steam, nuclear, gas turbine & combined cycle, hydro & pump storage plant.

WG2 will also oversee the ongoing development of the availability statistics database, including the contents, the required software, security issues and other important information.

Work Group 3 (WG3): “New Renewables” and Environment

WG3 will promote the introduction of performance indicators for renewable energy generating plant (wind, geothermal, solar and biomass) developed by the Committee. It will also assess selected transitional technology issues and environmental factors related to non-conventional technologies.

Work Group 4 (WG4): Markets and Risk Management

WG4 will monitor the development of power markets, in particular from the market risk management point of view, including operational risks. It will assess various risk management strategies used by market players around the world and develop recommendations for a wider deployment of successful strategies.

2. Industry Outlook

As of 2007, the global electric supply industry (ESI) continues to see significant change. As in the past, the drivers for this change are actually quite diverse and represent a wide range of issues including:

1 Continued restructuring and re-regulation of the ESI. Globally, one can quickly see that different regions possess radically different regulatory frameworks and, in some cases, different forms of energy markets. Activities include:

- Continued implementation of regional transmission entities or markets for wholesale generation. Typically, rules governing how generators bid, are committed, and are paid, and provide "rules" governing access for generation based on market aggregate demand, reliability requirements, etc.
- Promulgation of new regulations that govern generation emissions – regulations can address NOX, SO2, CO2, particulate, and trace elements.
- Creation of "new" markets to address emissions cap and trade programs.
- Nationalization of power industries such as Venezuela.

2 Lowered reserve margins due to lack of new construction of new plant to keep pace with global demand. Current trends are:

- Significant new coal-fired generation being proposed due to cost/availability; however, the number of units permitted or under construction varies by region based on regulatory hurdles and environmental lobbies for more green alternatives.
- Modest buildout of combined cycle generation facilities.
- Strong demand for new technologies that can deliver improved efficiency, ultra low emissions, and negligible carbon footprint.
- In some countries/regions, the obligation to serve demand lies with the transmission system operator vs. generators. In such cases, markets structures must provide adequate incentives for adequate generation to be present.

3 Increasingly strong overall view of environmental issues and the responsibilities of generation entities and customers to fundamentally more "green." Key aspects include:

- For generation, focus on greenhouse gas emissions reductions through variety of initiatives including increased use of renewables in the portfolio, potential for resurgence of nuclear, drive for emissions-neutral coal-fired generation via carbon capture or sequestration.
- Renewed focus on demand-side management, smart grid initiatives to support energy storage and bi-directional energy flow at distribution level, etc.

- Growing desire to measure companies, countries, or other entities in terms of their impact on environmental issues.
- In some regions such as the US, new environmental regulations at the national, state, and localities, is driving large capital investments in control technologies.

4 Regional/national energy supply security increasing in importance due to higher cost of energy, risk of supply interruption, and lack of supply diversification from captive energy resources.

- Focus on energy diversification issues are typically highly inter-related with environmental issues.
- Significant physical distances between supply and demand exist.

Further, in the future, shifts in generation mix will impact picture of reliability and performance as different technologies are introduced for either environmental control or for power generation. This will likely lead to a situation where generation mix will simultaneously be impacted by further environmental controls applied to aging plant at the same time as different technologies (e.g., renewables, IGCC, Coal with carbon capture) are initially deployed.

2.1 Deregulation/Market Reform/Privatization

Deregulation/market reform and, in some cases, privatization has been at the forefront of the ESI for the last decade. Many prognostications have been made with respect to where the industry is headed with dramatically different views of the role of the market, separation of generation from transmission/distribution, and means for attracting capital investment to the sector where needed. Specifically, a closer look at this issue is warranted from a number of views.

1. What is the current status of regulation as it relates to power generation? Have such activities resulted in a more or less uniform regulation and market orientation worldwide?

2. Is it working? What are the implications as to further possible changes in structure or priorities in the ESI?

3. How do the current situation and possible future outcomes impact how "performance" will be defined, evaluated, and measured?

2.1.1 What Is The Current Status Of Regulation As It Relates To Power Generation?

In many regions of the world, government and regulatory policy is tending to "mix" market initiatives with environment.

In the United States, recent regulations are focused on environmental issues but with an eye toward influencing generation mix, efficiency, and sustainable energy goals. Similarly, for the EU, as set forth in the Commission of the European Communities' Green Paper entitled, "A European Strategy for Sustainable, Competitive and Secure Energy," it is recommended that three basic principles should form the basis for further energy policy. These are:

- Secure and reliable supplies
- Competition to assure that the best deal for the consumers
- Sustainable energy practices which reduce the environmental damage from energy.

Our focus in this section to address competition, open access, and market efficiency; a separate discussion of regulatory action to address environmental concerns is provided in Section 2.2.

Many pundits have offered various views of the current state of the industry – in turmoil, in transition, immature, stalled, etc. These are dramatically different views that were held as recently as 8 years ago when deregulation/competition/privatization was hailed as the solution for both incentivizing private capital investment and producing low-cost, reliable power. Radical changes were implemented very quickly by early-adopters; others were more cautious, implementing more modest changes. Today, changes in regulations currently tend to be more evolutionary than revolutionary at this point in time and focused principally on improving effectiveness of current situations vs. large-scale adoption of new strategies. For example, in both the European

"Liberalization brings new challenges; integration provides more choice of investments between import possibilities and building generation."

Union and the United States, the focus is to refine what is in place including:

- Further refinement/policy to assure security/reliability of supply
- Means to assure fair/reasonable access to the grid.
- Means to address issues such as transmission pricing and congestion management.
- Incorporation of additional environmental regulations.

The European Union is in the process of changing its electricity markets from many more or less separate monopolistic electricity markets with national supply of electricity into one single liberalized market. The implementation of the first liberalization Directive (96/92/EC) has resulted in fully liberalized electricity markets in some Member States, while there are still markets where not all parts of the liberalization aspects are in place yet. Another fundamental change is the integration into a single panEuropean market. Both have effects on investments.

The intentions of the Directives are to establish a competitive market for generation and supply with many unbundled companies, and a separate, naturally monopolistic, regulated sector for transmission and distribution. This reform is expected to lead to greater economic efficiency and lower prices, yet maintaining the very high security of electricity supply that Europe has enjoyed for many years[2].

To date, there is mixed success in terms of "standardization." In the United States, the Federal Energy Regulatory Commission (FERC) was forced to repeal its call for "standard market design" whereas, in the European Union, variations in the current structure of national markets are complicating further integration. In both cases the issue of who has authority to resolve differences is significant. In the United States, the power to regulate wholesale generation remains at the state level and it is incumbent on FERC to devise means to address its overall needs in cooperation with the states. In the EU, the Director General of Energy and Transport (DGET) is wrestling with similar issues.

Similarly, in other regions such as Asia, Sub-Sahara Africa, etc. the theme of "refinement" also holds true. In these regions, the focus of the refinement is closely aligned to address needed system expansion/reliability issues.

For example, for China, planned government sector reform and restructuring is being cautiously implemented with the goal for expanding investment by domestic and foreign energy companies and the resulting transition toward competitive markets. Given the critical role of energy to its continued economic growth, the Chinese government continues to push through reform and industry restructuring measures in order to encourage investment, improve sector efficiency, increase transparency, introduce more competition, and ultimately, to reduce the cost of energy to the consumer. Since 1980, the government has introduced a number of key measures to promote investment including the introduction of surcharges on consumption to finance projects, increased access to provincial and local government funds, creation of independent domestic companies and use of foreign partners. Substantial additional investment will be required given power demand growth projections.[3]

For emerging economies such as South Africa, the story is similar; while there is still interest in developing energy market/trading, most of the emphasis on recent regulations have been to address supply adequacy and reliability. In 1998, a comprehensive White paper was issued by the South African government outlining key objectives of the energy sector. This paper called for:

- Increasing access to affordable energy services
- Improving energy governance and stimulating economic development by encouraging competition with energy market.
- Where market failures are identified government will intervene through transparent, regulatory and other carefully defined and time delineated mechanisms, to insure delivery of energy services to consumers.
- Stimulating further fixed investment from both the local and foreign sources through good governance, stable, transparent, regulatory regimens and other appropriate policy instruments
- Managing energy-related environmental impact
- Security of supply through diversity

The Department of Minerals and Energy (DME) has subsequently been given the responsibility of ensuring diversified primary energy sources will be developed within the electricity sector. More recently, in a significant shift from 2003 strategy which called for 70/30 target, (Eskom to provide 70 percent of generation with the other 30 percent from independent power producers), currently the bulk of new generation is being provided by Eskom with less certainty as to role/scale of IPPs. Efforts continue to incorporate improved mechanisms for further opening of the market continues but as a subordinate goal to that of achieving needed generation and grid reliability targets.

2.1.2 Is it working?

This question has undoubtedly fomented significant debate around the ESI. There is no clear answer and widely divergent opinions.

One of the keys to answering this question is to first ask “in what context?”

- In terms of providing means to allow 3rd party access to the grid?
- In terms of providing effective means to assure fair and transparent compensation to participants?
- In terms of encouraging investment in both transmission and generation assets?
- In terms of incentivizing new capacity at right location/technology, given national security needs and long-term energy policy?

“Markets must first be designed and then implemented over a period of time.”

- In terms of lowering the overall costs to the end-user?

Clearly, in many regions, deregulation/market reform/privatization has opened up the generation sector to allow participation of 3rd parties. It is also clear that significant work has yielded transparent pricing or market structures.

Yet, to date, experiences have shown an inconsistent ability to attract needed capital investment. For countries which have created markets, promises of deregulation/privatization delivering the needed capital infusion have not been fully realized; for others with more traditional regulatory frameworks or government-backed generation assets, the problem is typically rooted in lack of reliable, transparent access to market for 3rd parties.

Similarly, the question of whether an effective market structure is capable of properly incentivizing private investors to invest in the appropriate technology, at the appropriate location, for the overall good of grid capability and reliability remains unanswered. In the United States, most would agree that current market structures coupled with current regulatory and permitting hurdles have not been successful in encouraging needed investment in transmission infrastructure; to some this is a short-term issue as we seek to refine market structure and rules, whereas to others, its an indication of the inability of markets to address such key issues.

Substantial debate continues as to whether deregulation/market reform/privatization has lowered the overall cost of electricity to end-users. Economists that favor deregulation look to deregulation to spur competition to improve the operating efficiency of power plants and lower the cost to consumers. For instance, in the United States, proponents most often cite the CERA Multi-client Study “Beyond the Crossroads: The Future Direction of Power Industry Restructuring.” This study examines the impact on the industry and offers a "grading" of the deregulation efforts in the United States over the past decade. This report notes that, “contrary to conventional wisdom, deregulation has lowered electric power prices for the majority of consumers compared with costs under traditional regulation. The majority of US consumers have paid less for electricity since the onset of power system deregulation in 1997, achieving total savings of about $34 billion relative to the costs if traditional regulation had continued.”

Critics of current electricity markets both dispute the finding of the CERA study and emphasize that the problem lies in how competition is managed. In fact, differences in opinion between key policy makers at the state and federal level have essentially stalled further significant new restructuring “activity.” At this point in time, 23 states receive some portion of their wholesale power through a RTO; however, two large blocks of states in oppose further formation of RTOs. In the hybrid electric system that now serves the United States, three distinct schools of thought have emerged: (1) return to rate regulation to the extent possible; 2) do not restructure any additional states and try to maintain the status quo; (3) move ahead with restructuring and expansion fo RTOs or risk further crises.[5]

In the mid 1990's the European Commission (EC) began liberalising the European Union's electricity industries. Under The Treaty of Rome, which established the European Community, the member states cannot be forced to changes in the assets ownership. The European Community's successor, the European Union (EU), on the other hand, is imposing strict requirements on all types of unbundling. However, the capital intensity of the power industry and the economies of scale it can generate do not fit into the "one size fits all" approach.

The first directive issued by EC in 1996 mandated third party access to the electricity networks and forced a certain minimal unbundling of the industry in order to encourage competition in generation. In parallel with electricity industry liberalisation the EC also introduced liberalisation of gas industry. This was mainly due to the increasing reliance on gas-fired generation. The aim of the European Commission was to create a competitive market where customer choice would drive the allocation of resources in the industry and where national borders would not present any barriers to energy flows between countries.

Often the market liberalisation process turns out to be far more complex than the original design. Adding to this complexity is the reality that the provision of electricity is a highly political issue, given the severe consequences of making mistakes. When the energy industry liberalisation process began, the security of Europe's energy supplies was not an issue. Fossil fuel prices were historically low and many European countries had a surplus of generation capacity. This has greatly changed over the past few years, and today European energy prices are not just extremely high by historical standards but also highly volatile. Concerns about long-term supply security of primary energy have reached the top of the political agenda in many of the EU member states and have become an important factor in the European energy debate.

The principle of "subsidiarity" adopted by all EU countries means that EC policy must be at a high level leaving room for a wide variation in implementation practices among the various countries, and member states have taken advantage of this wherever possible. The range of approaches across Europe makes it much more difficult to move beyond national markets to pan-European markets.

A new feature of the European electricity market is exchanges for trading services for electricity market participants. Some exchanges are new, Nordpool in Scandinavia, for example, while others are integrated into well-established energy exchanges. Recently, traditional stock markets have also begun to take interest in power exchanges from a purely commercial point of view. Exchanges and traders are influencing the market in a number of ways. For example, they demand a simplification of the power exchange process but this can only be achieved with the full cooperation of TSOs involved. TSOs on the other hand, are not particularly open to letting traders have full insights into their system management activities.

The EC has recently suggested a division of Europe into eight regions to advance regional markets: Western Europe, Iberia, UK & Ireland, Italy, South East Europe, Eastern Europe, Baltic States and Scandinavia. The original deadline for achieving a single European energy market set for 2007 will not be met, even if most countries will have complied with their basic EU obligations by that date. It is obvious however that a fully functioning efficient single energy market will still take years to complete. So far, a few efficient national markets have emerged but enlarging these to regional markets and ultimately to a single European market will still require a major effort.

The EC is concerned with the delays in the development of a single energy market, but it is now getting support from new and powerful allies. The consolidation of a few traditional utilities in Europe and their new and significant trading activities in more than one market means that large national champions are looking for business opportunities across Europe.

In this uncertain environment, the long-term price of natural gas and the costs of CO_2 abatement are critical to the success of the EU power market. If both CO_2 and natural gas prices remain high, investment in nuclear power and in renewables will become more attractive. This could lead to an exodus of energy intensive industries from Europe to low-cost countries. The political consequences of this might create a need for major policy adjustments. If prices drop, producers with considerable gas resources might move into the generation business. This would give them long-term strategic benefits in Europe's electricity industries since they would be able to mitigate their off-take risks.

On 8 March 2006, the EC published a green paper on energy policy for discussion at the a meeting of the European Council on 23 March. All market players agreed that energy should remain at the top of the EU agenda due to concerns about security of supply and high energy cost. The paper itself concludes that energy policy in Europe should have three main objectives: sustainability, competitiveness and security of supply.

The debate of the issues following paper's publication emphasised the political difficulties encountered so far, but also concluded that there were grounds for optimism and significant progress could be made in the implementation of the agenda set by EC. Some of the issues raised in the paper were considered too weak, and there were too few "hard" suggestions such as a pan-European Grid or pan-European regulation.

The experience in the United Kingdom, for example, tells an interesting story. The market dominance by a few major generators in the country was broken up at an early stage, and the market rules were revisited again after seven years of experience. It is now considered to have a successful market which delivers considerable consumer value while, despite complaints from investors. A number of over-optimistic investors have made heavy losses in the UK market, although consumers have by and large benefited substantially.

The Nordic market is also considered to have be a success, although it began from quite a different starting point. Other European electricity markets are perceived to be less successful, mainly because of dominating oligopolies. The EC competition directorate is also seriously concerned with the slow rate of market development in Europe and is conducting a major investigation into its causes.

Only time will tell if the current EU agenda for Europe's energy industries will bring sustainability, competitiveness and supply security to its citizens.

Similar, mixed results appear to have been realized for developing. For example, in "Economic regulation of SA's public utilities" Cornel van Basten, Trade & Industrial Policy Strategies (TIPS), May 2007, the authors suggest that "… to date, the effects of current regulatory reforms in developing countries are debatable. There seems to be serious errors in the sequencing of reforms, which have had widespread and significantly negative impacts, especially on the poor.

Where privatization has been undertaken in a hurry, under international pressure, and in the absence of good regulatory controls and competent institutions, as in Russia for example, the result has been the massive enrichment of a small elite, a flood of capital out of the country, rapid industrial decline, damage to social institutions and an enormous increase in the number of people living in poverty. In contrast China, where the development of a market economy has been both gradual and accompanied by strong state support for market-based regulatory reform, has enjoyed well above average growth and an impressive reduction in poverty levels."

- How does the current mixed "market" situation and possible future outcomes impact how "performance" will be defined, evaluated, and measured?

2.2 Environmental

In the European Union, energy policy focuses on its commitment for reducing greenhouse gas emissions. In 2007, the European council of heads of state and government adopted a comprehensive energy policy for Europe that:

- Targets 20 percent reduction in the EU's greenhouse gas emissions by 2020.
- Establishes a binding obligation for 20 percent renewables in generation portfolio (from the prior 6.5 percent obligation).
- Targets overall improvement in energy efficiency for the sector of 20 percent.

The policy applied to enforce its objectives is to be based on the "polluter pays" principle with the goal being that environmental costs are internalized in the cost of generation similar to other production costs. Most energy intensive industries address this policy through the EU emission trading program.

As set forth in the Commission of the European Communities' Green Paper entitled, "A European Strategy for Sustainable, Competitive and Secure Energy," it is recommended that three basic principles should form the basis for further energy policy. These are:

- Secure and reliable supplies
- Competition to assure that the best deal for the consumers
- Sustainable energy practices which reduce the environmental damage from energy.

The situation is very similar in the United States where recent regulation at both federal and state levels has been recently enacted. On March 10, 2005, the Environmental Protection Agency (EPA) finalized the Clean Air Interstate Rule (CAIR), a rule that will achieve the largest reduction in air pollution in more than a decade.

As noted in the final CAIR rule, this action, called the Interstate Air Quality Rule when it was proposed in January 2004, offers steep and sustained reductions in air pollution as well as dramatic health benefits at more than 25 times greater than the cost by 2015. CAIR achieves substantial reductions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) emissions through the use of the cap and trade approach; it is a key component of the Administration's plan to help over 450 counties in the eastern U.S. meet EPA's protective air quality standards for ozone or fine particles.

States must achieve the required emission reductions using one of two compliance options: 1) meet the state's emission budget by requiring power plants to participate in an EPA-administered interstate cap and trade system that caps emissions in two stages, or 2) meet an individual state emissions budget through measures of the state's choosing.

During 2007, there has been strong movement to address CO2 and global warming issue through additional regulation. To date, there are a number of proposals at the national level that all call for significant CO2 reductions from the power generation sector. Significant technical issues to realize such reductions not withstanding, it appears that Federal regulations in some form will be promulgated in the US in the not too distant future. In some cases – specifically California and states participating in the Regional Greenhouse Gas Initiative (RGGI) – state legislatures are taking action in advance of the Federal government.

- How will significant deployment of new environmental equipment impact power plant performance and means for measuring/benchmarking performance?

2.3 New Generation Trends

In the European Union, the movement toward controlling/reducing greenhouse gas emissions is resulting in a far different picture in terms of new generation. Many experts believe that is unlikely that significant coal plant will be built until technologies are for collecting or storing CO2 are to be installed; in the near term, there are great pressures to incorporate more renewable sources, followed by gas plant, and, in some countries, nuclear.

In the United States, the situation is much more fluid. The recent and dramatic increase in public interest with respect to global warming – with the issue becoming highly politicized given the impending elections. – has led to projections for the forecasted deployment of 100+ conventional coal units to be reduced about three-fold.

Given the above, it appears that substantive changes in technology mix will evolve as technology options for generation are increasingly scrutinized in the wake of increased sensitivity to environmental issues. In developed countries, this has largely resulted in emphasis on leveraging renewable technologies to degree possible, a possible renewal of interest in nuclear generation, and increased interest in leveraging non-traditional technologies such as integrated coal gasification/combined cycle (IGCC) with offer superior efficiency and emissions performance. Implementation of CO_2 sequestration or carbon capture would further change the generation landscape. Clearly, such changes will impact expectations as to performance.

In the near term, the situation may differ for developing countries. For example, high growth in demand in regions like China is being addressed with rapid buildout of new plant – mostly conventional coal but also gas and nuclear. Similarly, in South Africa, projected shortfalls in generation are driving efforts to re-commission previously mothballed units as well as fast-track the construction of significant new generation. It is expected that South Africa may require on the order of 1000MW of new capacity each year for the next 20 years; further, within the South African Power Pool as a whole, the requirement could be as much as 1400MW/ yr[9]. A build out of this significance will limit its ability to leverage new clean coal technologies in the near term.

- Differences in technology (vs. historical) is quickly becoming a reality and must be factored into data collection, analysis, and benchmarking efforts of PGP in the future.

2.4 Sustainability

If one considers the shift from technical to commercial availability to be a reality of the privatization/deregulation movements in the ESI, is it possible that further changes in "goals" could be tied to the global warming issues?

Sustainable development and transparency relate to the ability to "meet the needs of the present without compromising the ability of the future generations to meet their own needs."[8]

"The urgency and magnitude of risks and threats to our collective sustainability, alongside increasing choice and opportunities, will make transparency about economic, environmental, and social impacts a fundamental component in effective stakeholder relations, investment decisions, and other market relations."[8]

Clearly, at this point, the idea of tying power production performance measures to evolving sustainability standards is quite premature. However, as such processes/programmes mature, it will be important to consider how to integrate such measures into future performance standards or measures.

- How will evolving "performance measures" such as those tied to sustainability potentially impact power generation goals/objectives and metrics?

3. Implications for the Future

WG1's primary focus is to analyse the best ways to measure, evaluate, and apply power plant performance and availability data to promote plant performance improvements worldwide. From the aspect of this paper, it is not our goal to either support or challenge the hypothesis of whether markets, regulation, or technology area effective or not but, rather, focus on impacts on how the continued presence and importance of these drivers clearly impacts:

- Goals/roles of the generator
- Applicable measures/means in which "performance" is evaluated and optimized by the generator.
- How commercial power producers, whether regulated or deregulated, feel the need to address performance

The rapid rise in regulations throughout the world will result in the corresponding retrofit of substantial equipment on existing plant as well as the creation of new requirements for new plants.

The presence of additional environmental equipment increases the complexity of operations and provides further performance challenges. It is possible that the installation of such equipment could impact performance in a number of ways including:

- Available generation
- Maximum capacity given potential for derates and additional auxiliary power requirements
- Variable O&M costs to include sorbent, reagents, chemicals, etc.
- Environmental costs to cover emissions.

These impacts become significantly more significant IF evolving CO_2 legislation translates to the addition of CO_2 capture and/or carbon sequestration equipment. Either of these options will have a major and as of yet unmeasured impact on plant performance.

During the 90's, the PGP investigated if the large-scale installation of Flue Gas Desulphurization (FGD) equipment impacted plant availability based on experience from the United States, Germany, and Japan. This study concluded that performance was not substantially impacted after an appropriate break-in period. It should be noted, however, that this body of work considered only technical availability indicators (i.e., unplanned capability loss factor, unavailability factor, etc.) vs. commercial availability indicators.

Clearly, the dramatic changes occurring in the ESI worldwide discussed in Section 2 will continue to have major ramifications as to how performance is viewed, priorities, goals, and objectives of the power generation entities worldwide. Similarly, PGP's work will continue to evaluate ways to continue to measure and improve performance in the context of the evolving industry. Key elements to be factored into future work would include:

- Increased focus on renewable energy sources

- Increased importance of energy efficiency

- Increased utilization of new, evolving technologies to address, for example, CO2 capture or sequestration. To what degree will the introduction of such technologies impact expected plant performance?

- Introduction of new generation technologies on a larger scale such as advanced supercritical coal-fired generation or integrated coal gasification/combined cycle (IGCC)

- Challenges arising from integration of renewables within regional generation portfolio.

Similarly, PGP's work must consider the increasingly complex measures of performance. Specifically, in addition to technical and commercial performance, further analysis is warranted on the following:

- How should the industry measure performance in the future? Are there other performance measures or metrics to address such issues as sustainability?

- How will changes between developed and developing country priorities alter this picture? Are additional tools/techniques going to be required to "bridge" performance across different regions/situations?

4. Leveraging Performance Data

4.1 Establishing an Improved Performance Measuring Framework

In recent years the need to develop and use new performance indices, which more accurately reflect the current market place, has taken on a high degree of urgency. It is brought on by the need of large power consumers for lower electricity prices in order to compete in the global economy. Additional costs or taxes associated environmental regulations is creating further financial tension.

To meet this need electricity generators are being compelled to reduce their costs. Decision-making at all levels is being affected and the old “technical” definitions of availability are being amended to incorporate economics in order to link better plant performance with the actual cost of electricity supply. Rather than applying traditional measures that are calculated over both demand and non-demand periods, new availability terms are considering only the hours that the plant would have been dispatched and the financial consequences to the company’s bottom line from the failure to generate during those hours.

During the most recent triennial period our activities focused on establishing a realistic approach for “measuring” performance in the future. Building on our prior work, a substantial work activity for WG1 was the documentation/cataloguing of both traditional and new commercial performance indicators. A summary of all indicators and their calculations is included in Appendix A for reference.

The purpose of this effort is two-fold:

- Commercial indicators are more relevant for the large population of generators operating within deregulated or quasi-deregulated markets.
- The ability to compare “performance” of plants across markets must consider the realities of different economics/priorities within each market; hence, such comparison must consider the “commercial” aspects of performance.

Our continued assessment of the industry and its trends suggests that while “commercial” metrics are currently the best means for addressing performance, *specialized processes and tools are needed* to support comparison of performance across facilities. Such capabilities are necessary for one to relate commercial performance objectives to its technical counterparts. This provides a basis for the following:

- For a generator within an evolving market, a means to consider what optimal performance objectives should be, given commercial realities, role of the plant in the market, etc.
- For comparison of performance of a population of “similar” units across markets, it allows one to consider differences in value associated with specific performance metrics. To provide means to investigate if, for future WG1 efforts, it is possible to employ such analytics to “normalize” plant performance across markets to promote benchmarking and identify best-of-class performance.

4.2 Overview Of The PGP Performance Model

- Means to extend this framework to consider other forms of metrics or indices. For example, significant new work is being performed for measuring environmental performance and/or sustainability metrics.

To address this issue, Working Group 1 has developed a new computer-based tool to evaluate and compare technical and performance metrics. A series of case studies are also presented within the context of the model to illustrate how to better apply and leverage both peer group data and as well the broader set of indicators. This model also fully documents and provides basis of calculations for all major current technical and performance indicators.

Given that the problem has now been identified, how do we solve it? How do we design a modelling tool to recognize drastically differing plants in different situations and combine them into a common side-by-side analysis that presents them for an accurate and fair commercial evaluation? This was the primary question at hand during the development of the technical and commercial availability calculator, and was used to help guide its development. This section of the paper attempts to describe the essence of the calculator and show how the tool attempts to answer this question.

The model provides means for the user to analyze many facilities, even for technologies that the user does not fully understand. It provides a medium for analyzing and presenting a thorough availability and economic comparison for various facilities, technologies, markets, and obligations. It serves as an educational tool that facilitates the quick comparison of plants that are difficult to compare side-by-side.

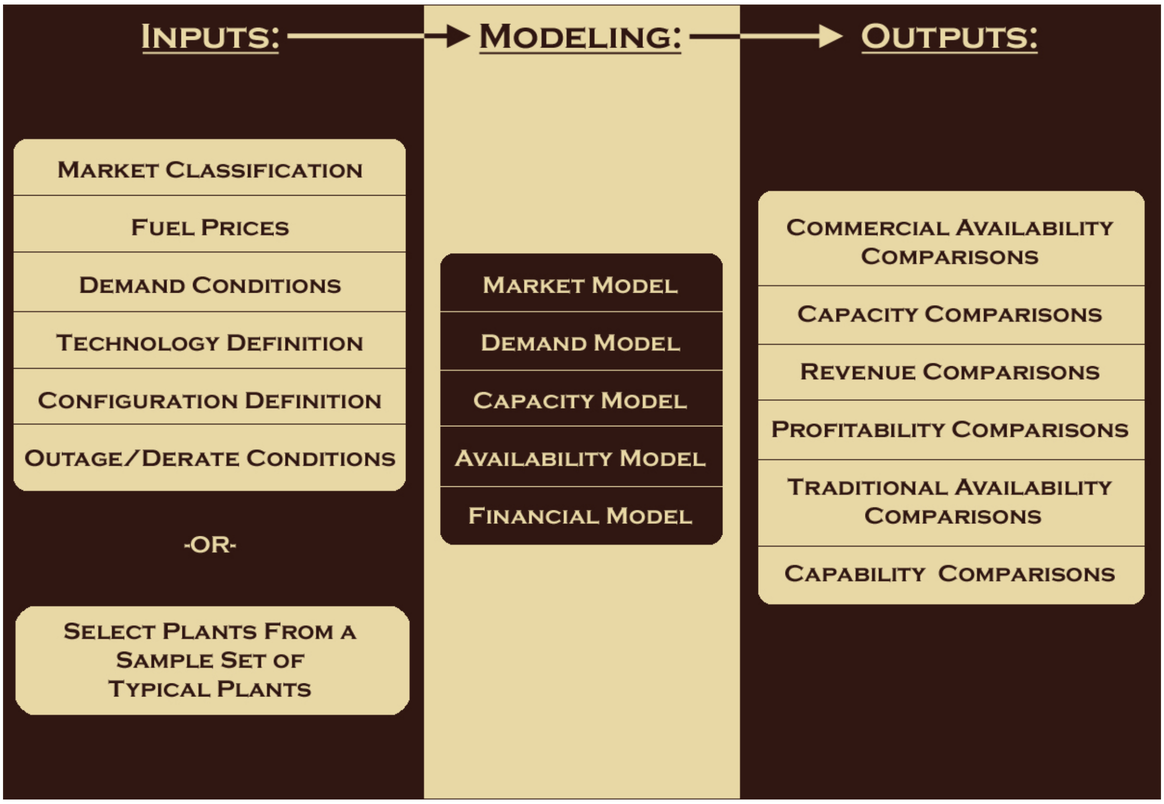
4.2.1 Design Approach

The following approach was taken when designing the PGP model to ensure that it met all of its functional objectives. First, the metrics had to be determined to compare dissimilar plants with differing markets, demand schedules, and outage strategies. The determination of objective plant comparison metrics and trend sets were based largely on the research conducted by the PGP. Once the most effective cross-plant output comparison metrics were defined, the inputs and the models necessary to generate these outputs had to be defined. A rough design of the models and their inputs was established, then they were refined and the easiest mode of input collection was determined. Finally, the design was developed and case studies loaded for testing.

4.2.2 Data Flow

Figure 4-1 outlines the flow of information through the modelling tool. The first column contains the inputs necessary to feed the models. The second column contains the models that simulate the plants and their markets. The third column contains all comparisons that are generated to easily contrast the plants side-by-side.

Figure 4-1
Calculator Modelling Data Flow



4.2.3 Outputs

Before designing PGP model, the metrics by which to provide a true comparison had to be determined. The analysis must consider various performance metrics across the plants including:

- Commercial Availability
- Traditional Availability
- Capacity
- Capability
- Revenue
- Costs
- Profitability (or Operating Margin)

The following section includes a brief description of each of the outputs found within the data flow chart:

Commercial Availability Comparisons

The commercial availability comparisons allow for a fair comparison of plants across differing regulatory, market, and demand scenarios. The definitions that are compared are a result of a survey collected from multiple real plant staffs across differing technologies and markets. They are intended to represent an availability metric that is independent of a particular market or regulatory situation.

Capacity Comparisons:

The capacity can be influenced by several factors including overall demand on the plant, as well as too high cost of operation, or low power prices and other influences. This modelling tool considers each of these separately to be flexible enough to fairly compare the differing plants. The capacity comparisons display a comparison across plants for the differing capacity factors as well as the overall generation (MWh) generated.

Revenue Comparisons:

The revenue across the plants can vary significantly depending upon factors such as the market price of power, demand, as well as outages and derates. These differing revenues across plants can be compared by placing the actual and maximum achievable revenues for each plant side-by-side.

Profitability Comparisons:

The profitability of the plants can be compared by investigating the revenues and costs of each of the plants and exploring how much profit each plant makes in their situations. It is valuable to review and compare the differences in fuel, variable O&M, and fixed O&M costs each of the plants experience. It is useful for investigating, for a given case study, where exactly the revenue goes for each plant. How much of the revenue is spent to cover a cost, or how much is considered profit?

Traditional Availability Comparisons:

The traditional availability metrics are calculated for comparison such as Equivalent Availability Rate, Equivalent Forced Outage Rate, Forced Outage Factor, Forced Outage Rate, and Planned Outage Factor. These are the traditional measures used to compare like plants independent of their market situation.

Capability Comparisons:

The capability factors are calculated and displayed for ease of comparison across plants. The Unit Capability Factor and Unplanned Capability Loss Factor are calculated for all plants being considered.

4.2.4 Elements of the PGP Model

In order to attain these comparisons, there must be a simulation engine to model the systems that generate these comparison metrics. With this in mind, the following models for each plant have been integrated into the PGP model: Market, Demand, Capacity, Availability and Financial.The following section includes a brief description of each of the models found within the data flow chart:

Market Model:

The market model uses the supplied market classifications for each plant to generate a simulation of the market price for every hour of every day throughout a given year for each plant. This is achieved by using the market curves and peak prices defined in the model inputs. This model of the market price fluctuations provides a foundation for the financial model. It also provides key inputs into the calculation of the maximum achievable and actual revenue that can be generated over a period of time, and is used to determine when it is profitable to generate for each plant.

Demand Model:

The Demand Model simulates the MWh demand for each of the plants being investigated. It calculates the amount of power that the grid demands for each individual plant independent of economics, and is used to characterize the maximum achievable amount of generation desired from each plant. This is used as an input into the capacity and financial model so the maximum achievable amount of economically viable generation and cost of generation can be modelled.

Capacity Model:

The capacity model uses the demand model combined with the operation costs and availability model to simulate the amount of total generation that each of the plants will profitably generate considering economics. This model, combined with the availability model, considers outages/derates and the time ranges which the plant does not generate when it is not profitable to do so. This model tracks the maximum achievable capacitance achievable by each plant as well as the actual profitable generation for every hour of every day of the year for each plant.

Availability Model:

The availability model uses inputs from the outage/derate conditions, and uses outputs from the capacity model to calculate when the plants will generate MWh and when they will be in outage or derate. This is used by the financial model to calculate actual costs, and actual revenue for each plant, and ultimately the profitability for each plant.

Financial Model:

The financial model accepts inputs from all of the other models and performs all financial calculations for each plant. It uses the maximum achievable and actual revenue and costs for each plant from other models to generate the actual profitability for all plants for comparison.

4.2.5 Inputs

In order for the models to accurately simulate, they must be supplied with crucial INPUTS for each plant including: Market Classification, Typical Fuel Price, Demand Conditions, Plant Technology Identification, Operating Characteristics, and Outage/Derate Conditions. The following section includes a brief description of each of the inputs found within the data flow chart:

Market Classification:

The number of differing market situations that exist in the world is quite vast and continuing to evolve. For each plant, variations in market situation drive daily, monthly, and seasonal market price fluctuations. This makes it challenging to fairly compare two *identical* plants in *different* markets, and even more challenging to compare two *dissimilar* plants in *different* markets. The market which a plant resides determines distinct differences between the profitability and dispatch of one plant to another, and thus is a large factor which must be identified for each plant within the PGP model. Since defining a plant's market is such a diverse and complex exercise, we have developed a library of typical markets from which to choose. The user chooses markets from the library to easily define each plant's market. It should be noted that the library of market definitions contained within the PGP model characterizes a broad array of both *regulated* and *deregulated* markets.

Since each plant's unique market can change dramatically throughout the course of a year, the calculator also allows the user the flexibility to define a separate market profile and peak price for *each season*. If the plant's market is steady throughout the year, a single profile can be identified for each season. The model uses these market profiles and peak power prices to define the market price curves for each plant. These provide a foundation from which the model determines each plant's dispatch and revenue.

Demand Conditions:

Similar to the market classification, every plant has its own unique power *demand profile*. As noted in Section 2, changes in the world's generation technologies impact the demand profiles we see for plants. The load demand for each plant greatly influences how the plant functions in its market, thus proves to be an important input into the analysis and must also be captured. Similar to the library of market definitions, the model contains a library of demand profiles to classify each plant's load demand before economics and costs are considered. The model uses this demand profile and plant capacity to define load curve and thus revenue that the plant might achieve without considering outages and derates.

Typical Fuel Prices:

Fuel costs make up a majority of the costs associated with running a power plant, and thus is a very important input into the model. The model relies heavily on this value to determine when it is "profitable" to generate for each plant – a key determinant for assessing commercial availability.

4.3 PGP Model Examples

Technology Definition:

The model must know what technologies each plant contains. This provides needed insight into the model for various reasons, such as assignment of the correct estimated fixed and variable operations and maintenance costs.

Outage/Derate Conditions:

Outages and derates play a large role in determining the commercial availability of each unit. Since they differ from plant to plant, and technology to technology, they must be entered as an input into the model. The number of outages and derates, size, duration, and their timing can be a huge differentiating factor between plants and their availability.

Select Plants

In this case, the PGP model provides a library of typical plants from which to choose and populate the inputs. This was provided to make it easier to quickly load plants for educational comparison, and is very useful when comparing against an unknown technology. This is also useful to speed up the input process, by easily pre-populating the model with inputs from a similar technology, before refining data to the exact scenario desired.

By developing an easy-to-use calculator that provides a side-by-side comparison report for all of the plants desired, we believe that we are one step closer to providing a method to fairly contrast one plant against another, regardless of the plants internal or external situation.

To facilitate both the use and understanding of the PGP model, a number of examples or case studies have been developed. These examples can be rapidly accessed within the model by using the hyperlink buttons on the "Main" page. Once the button next to the study is clicked, it populates the "Scenarios" tab with a set of plants that have been used to investigate a particular situation.

The following list contains a brief description of each of the examples:

- **Example 1**: This example compares a large pulverized coal plant in both a regulated and deregulated market across varying dispatch curves.
- **Example 2**: This example compares an oil-fired steam plant in both a regulated and deregulated market.
- **Example 3**: This example compares a peaking GE 9FA plant in both a regulated and deregulated market.
- **Example 4**: This example compares a small pulverized coal plant in both a regulated and deregulated market.
- **Example 5**: This example compares a large and small pulverized coal, oil-fired, and peaking GE 9FA in a regulated market.
- **Example 6:** This example compares the same plants from study 5, but immersed in a deregulated market.

- **Example 7:** This example compares a large baseloaded pulverized coal plant in both a regulated and deregulated market across varying forced and scheduled outage magnitudes.

A detailed presentation of each example is presented in Appendix B. A review of Section 5 is highly recommended as familiarity with the model structure and terminology will be quite helpful.

4.3.1 Example 1: 800 MW Pulverized Coal Across Various Markets/Loads

Study Description

This example compares the performance and economics for a pulverized coal plant in both a regulated vs. a deregulated market. This example is based on a large coal-fired power plant.

Three different load shapes are considered: 1) the plant is base loaded, 2) the plant typically follows load at night, and 3) unit demand also decreases over the weekend. Analyzing various load shapes allows us to see how sensitive results are to the shape of the load demand.

Table 4-1
4.3.1 Plants Being Investigated - Study 1

Plant	MW	Technology	Demand	Market	$/ MWH Winter	Spring/Fall	Summer
1	800	Pulverized Coal	Baseload Plant	Regulated	60	50	70
2	800	Pulverized Coal	Baseload w/ Nightly Load Following	Regulated	60	50	70
3	800	Pulverized Coal	Daily Load Min Load Night and Weekend	Regulated	60	50	70
4	800	Pulverized Coal	Baseload Plant	Deregulated	80	100	120
5	800	Pulverized Coal	Baseload w/ Nightly Load Following	Deregulated	80	100	120
6	800	Pulverized Coal	Daily Full Load, Min Load Night and Weekend	Deregulated	80	100	120

Study Objective:

This example is used to illustrate the differences in capacity factor, profitability, and performance for large pulverized coal facilities in regulated vs. deregulated markets. This example also shows to what degree the different load demand curves affect its availability and financial metrics in both markets.

It is important to note that for this example, each unit is presumed to have "identical" technical performance. Specifically, each unit has the same planned, forced, and maintenance hours; similarly, costs of production including unit fuel costs and variable O&M are also held constant

Study Highlights:

In this example, the key difference between the regulated environment and the deregulated environment lies in the difference in market price characteristics. As is frequently the case, this example is based on the premise that the predicted value of generation during peak period in a deregulated market can be substantially higher than the price predicted for the regulated market.

In a fully regulated market, the price is typically equal to the system lambda or incremental cost of generating the next MW of power.

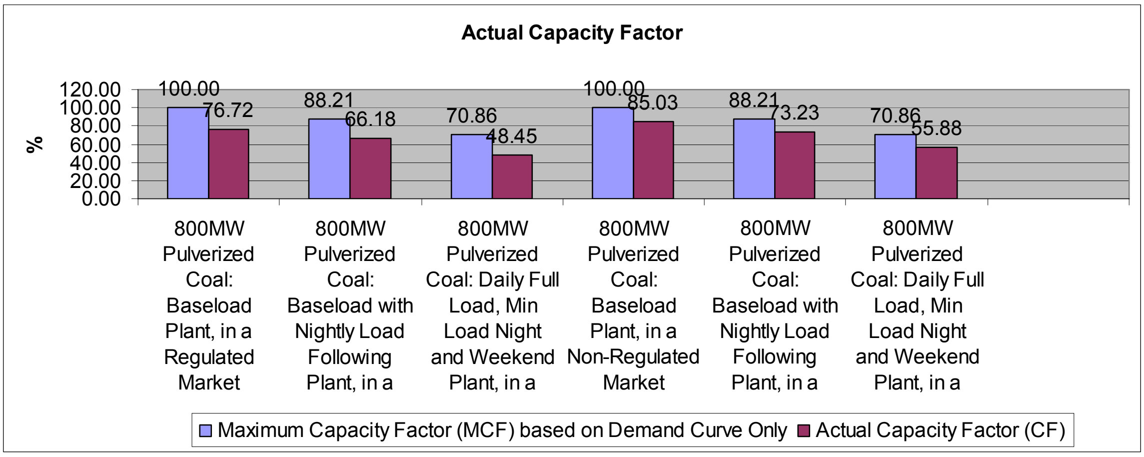
Key differences in market and load profiles had the largest affect on the capacity factors and the profitability of a large coal plant. The deregulated market allowed the plant to operate profitably more often throughout the period as illustrated by the following bar graph. The actual capacity factor (purple bar) is higher in the deregulated market, showing that the plant is generating profitable MW for nearly 7-8% more time during the period. The difference in capacity factor is economically driven.

The profitability was predominantly different between the regulated and deregulated markets. The deregulated market allowed the large coal plant to generate more profit as displayed in the following table. The total margin in the deregulated market is over 3 times the total margin in a regulated market, for every load profile investigated for the large coal plant.

Traditional availability metrics for the differing situations that the large coal in this example were quite similar; values for the deregulated market indicated slightly lower forced outage *rates*, due to the increased capacity and generation over the period (and same lost outage hours).

When considering commercial availability, the story is different. In this case, the large coal plants operating in a deregulated market have a higher commercial availability, due to the more profitable generating conditions realized throughout the period.

It should be noted that differences in commercial availability definitions will yield different results. Specifically, definitions that "weight" the opportunity cost associated with lost potential generation sales will vary more significantly from deregulated to regulated market vs. those that don't factor in the magnitude of the opportunity cost.



			800MW Pulverized Coal: Baseload Plant, in a Regulated Market	800MW Pulverized Coal: Baseload with Nightly Load Following Plant, in a Regulated Market	800MW Pulverized Coal: Daily Full Load, Min Load Night and Weekend Plant, in a Regulated Market	800MW Pulverized Coal: Baseload Plant, in a Non-Regulated Market	800MW Pulverized Coal: Baseload with Nightly Load Following Plant, in a Non-Regulated Market	800MW Pulverized Coal: Daily Full Load, Min Load Night and Weekend Plant, in a Non-Regulated Market
MCF	Maximum Capacity Factor (MCF) based on Demand Curve Only	%	100.00	88.21	70.86	100.00	88.21	70.86
CF	Actual Capacity Factor (CF)	%	76.72	66.18	48.45	85.03	73.23	55.88
REV	Actual Revenue	$	210,457,080	188,681,739	144,419,189	386,193,040	346,708,320	272,539,040
FOMC	Fixed O&M Costs	$	12,880,000	12,880,000	12,880,000	12,880,000	12,880,000	12,880,000
VOMC	Variable O&M Costs	$	16,236,366	14,006,405	10,254,083	17,995,214	15,499,486	11,827,166
FUELC	Fuel O&M Costs	$	105,891,211	91,347,734	66,875,636	117,362,161	101,085,387	77,135,051
VFUELC	Total Fuel and Variable O&M Costs	$	122,127,576	105,354,139	77,129,720	135,357,375	116,584,872	88,962,216
TOTOMC	Total O&M Costs	$	135,007,576	118,234,139	90,009,720	148,237,375	129,464,872	101,842,216
PROFVF	Margin (not factoring Fixed O&M costs)	$	88,329,504	83,327,600	67,289,469	250,835,665	230,123,447	183,576,823
PROF	Margin	$	75,449,504	70,447,600	54,409,469	237,955,665	217,243,447	170,696,823
	Actual Revenue per MWh	$/MWh	39.15	40.68	42.53	64.81	67.55	69.59
	Fixed O&M Costs per MWh	$/MWh	2.40	2.78	3.79	2.16	2.51	3.29
	Variable O&M Costs per MWh	$/MWh	3.02	3.02	3.02	3.02	3.02	3.02
	Fuel O&M Costs per MWh	$/MWh	19.70	19.70	19.70	19.70	19.70	19.70
	Total Fuel and Variable O&M Costs per MWh	$/MWh	22.72	22.72	22.72	22.72	22.72	22.72
	Total O&M Costs per MWh	$/MWh	25.11	25.49	26.51	24.88	25.23	26.00
	Margin (not factoring Fixed O&M costs) per MWh	$/MWh	16.43	17.97	19.82	42.10	44.84	46.88
	Margin per MWh	$/MWh	14.03	15.19	16.02	39.93	42.33	43.59

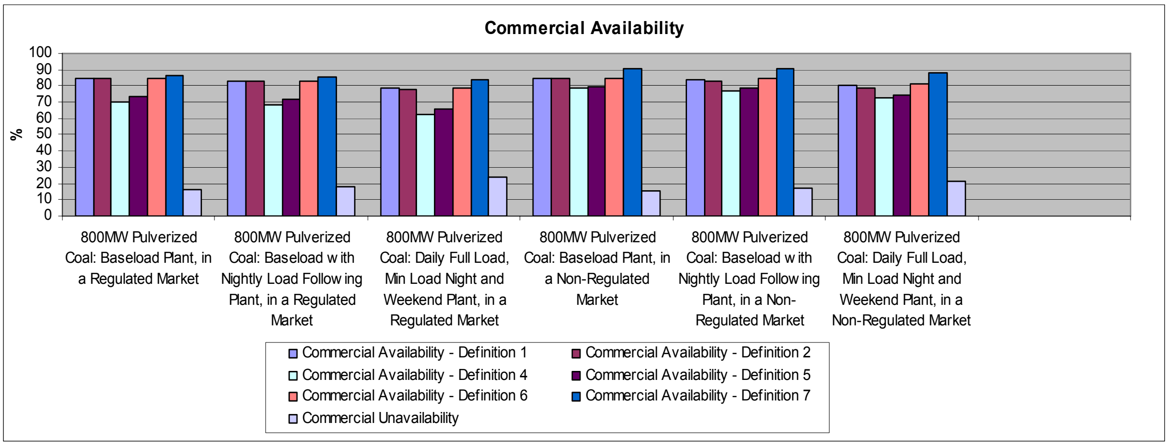


Table 4-2

4.3.2 Plants Being Investigated – Study 2

Plant	MW	Technology	Demand	Market	$/ MWH Winter	$/ MWH Spring/Fall	$/ MWH Summer
1	300	Oil-Fired Steam	Winter: Full Load, Min Load Nights/Weekends Spring/Fall: Full Load, Weekends Off Summer: Full Load, Min Load Nights	Regulated	60	50	70
2	300	Oil-Fired Steam	Winter: Full Load, Min Load Nights/Weekends Spring/Fall: Full Load, Weekends Off Summer: Full Load, Min Load Nights	Deregulated	80	100	120

From this simple example, it is clear that the relationships between commercial availability and technical availability will vary depending market structure, shape of load demand, and economics. Implications of what this means to one generator vs. the other is not as clear. For instance, one could postulate that the regulated unit, having less to gain financially, could lower its technical performance without incurring as significant a penalty. One would need to consider other factors such as its position in the dispatch, overall level of generation available vs. overall demand, etc. to determine if this is a reasonable position to take.

4.3.2 Example 2: 300 MW Oil-Fired Steam Across Various Markets/Loads

Study Description

This example compares the behavior for a typical oil-fired steam facility in a regulated vs. a deregulated market. This example is based on a 300 MW oil-fired unit.

In the interest of accuracy, individual demand curves were defined for each typical season. These seasonal demand curves include 1) a Winter full load behaviour that follows minimum load during nights and weekends 2) a Spring/Fall full load behaviour with no generation on weekends 3) a Summer full load behaviour with minimum load at nights.

Study Objective

The purpose of the example is to illustrate the difference in performance and economics for an oil-fired steam facility under regulated and unregulated market conditions. It contains the effects of a seasonally differing demand curves on the oil-fired steam plant for each market. It is intended to illustrate how a plant with moderate to high fuel costs can compete in differing markets.

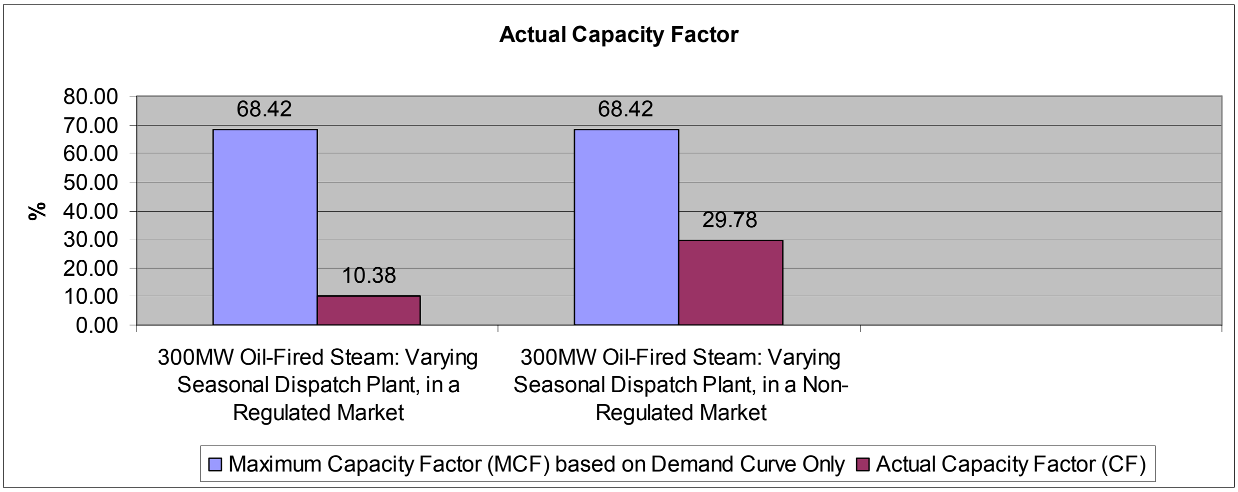
It is important to note that for this example, the technical inputs for each plant are essentially identical. More specifically, the plants all are presumed have same load demand curves, planned outage hours, scheduled outage hours, and incremental fuel and variable O&M costs. The only variable that differed between plants is the market type which the plant resides.

Study Highlights

As in the case of the first example, the difference in markets can seen in capacity factor and operating margin or profitability of the plants.

The oil-fired plant in the regulated market actually had a negative margin of about -$714,000, while the plant in the deregulated market made a margin of about $20,800,000. The negative margin for the plant in the regulated market is largely due to the high fuel costs associated with an oil-fired unit. The margin generated by the unit in the deregulated market was also greatly reduced due to this high fuel cost, as expected.

			300MW Oil-Fired Steam: Varying Seasonal Dispatch Plant, in a Regulated Market	300MW Oil-Fired Steam: Varying Seasonal Dispatch Plant, in a Non-Regulated Market
MCF	Maximum Capacity Factor (MCF) based on Demand Curve Only	%	68.42	68.42
CF	Actual Capacity Factor (CF)	%	10.38	29.78
REV	Actual Revenue	$	15,441,216	61,468,219
FOMC	Fixed O&M Costs	$	3,030,000	3,030,000
VOMC	Variable O&M Costs	$	201,951	579,085
FUELC	Fuel O&M Costs	$	12,923,507	37,057,534
VFUELC	Total Fuel and Variable O&M Costs	$	13,125,458	37,636,619
TOTOMC	Total O&M Costs	$	16,155,458	40,666,619
PROFVF	Margin (not factoring Fixed O&M costs)	$	2,315,758	23,831,599
PROF	Margin	$	(714,242)	20,801,599



The plant in the regulated market had a much lower capacity factor of ~10.4%, while the plant in the deregulated market had a capacity factor of ~29.8%. This difference is entirely due to economic reasons, based around the fact that the power prices in a deregulated market allowed for more time when the revenue generated by the plant surpassed the operational and maintenance costs. The plant in the deregulated market generated more MWh, thus incurred more costs of operation, but these greater costs were offset by the additional revenue and it turned a large profit.

When investigating differences in traditional availability between plants, it was found that the Equivalent Forced Outage Rate (EFOR) and Forced Outage Rate (FOR) for the regulated market were much higher than the same oil-fired plant in a deregulated market. This was due to the deregulated plant's higher capacity factor. The deregulated plant had more hours of generation, thus the rate of forced outage hours to generating hours was lower

4.3.3 Example 3: 242 MW GE 9FA Across Various Markets/Loads

Study Description

This example compares a peaking GE 9FA plant in both a regulated vs. a deregulated market. This example is based on a 242 MW natural gas-fired peaker.

Table 4-3

4.3.3 Plants Being Investigated

Plant	MW	Technology	Demand	Market	$/ MWH Winter	Spring/Fall	Summer
1	242	GE 9FA Peaker	Winter: Daily Peaking, Nights/Weekends Off Spring/Fall: Reserved Shutdown Summer: Twice Daily Peak, Morning, Afternoon	Regulated	60	50	70
2	242	GE 9FA Peaker	Winter: Daily Peaking, Nights/Weekends Off Spring/Fall: Reserved Shutdown Summer: Twice Daily Peak, Morning,	Deregulated	80	100	120

he following individual seasonal demand curves were applied: 1) Spring/Fall: reserved shutdown state, 2) Summer: twice daily peaking (morning/afternoon) demand curve 3) Winter: daily peaking, nights and weekends off demand curve.

Study Objective

This example illustrates the differences in capacity factor, profitability, and performance for peaker facilities in regulated vs. deregulated markets. This study also shows how much differing demand curves for a peaker unit influence its performance and financial metrics in both markets. It is intended to investigate how a plant with extremely high fuel costs reacts to differing power prices. It also illustrates the degree to which high priced fuel affects capacity factor and operating margins.

It is important to note that for this example, the technical inputs for each plant are identical. More specifically, the plants all have the same load demand curves, outage hours (planned/scheduled/maintenance), and incremental fuel and variable O&M costs. Similar to the oil-fired example 2, the only variable that differed between the gas-fired plants included the market type in which the plant resides.

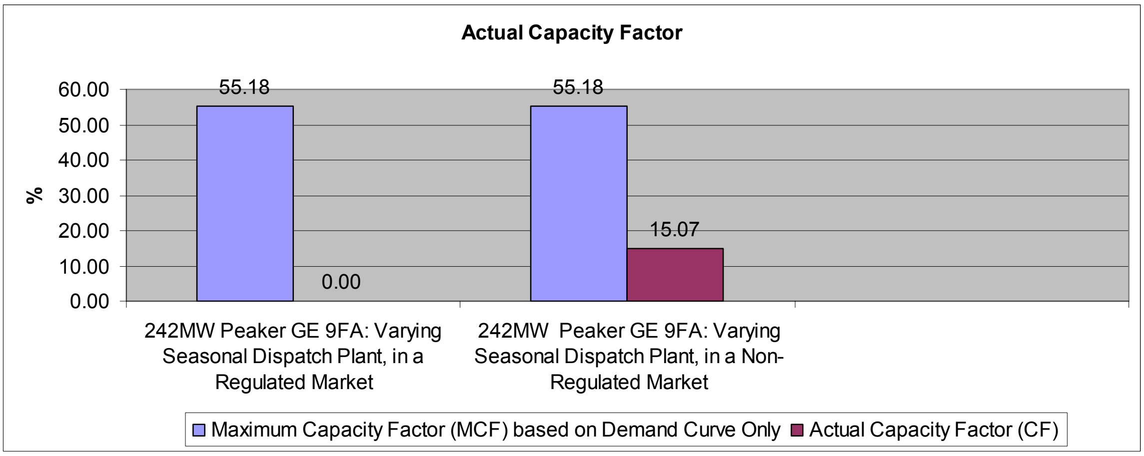
Study Highlights

The primary differences between a peaker in a regulated and deregulated market are in the capacity factor and margin, similar to the previous examples. The price of fuel is so high for a peaker that the fuel costs are difficult to offset, unless the market price of power is high enough. Market

prices only become this high within the modelled deregulated market.

Due to the high price of fuel and low price of power, the peaker in the regulated market did not run a single hour, giving it a capacity factor of 0%. The deregulated market price allowed for a 15% capacity factor, only operating during time periods when the market price of power is at its highest The cost of natural gas used by the model was $7/MBtu.

Another major difference was present in the revenue and margin for the plants. In the regulated market, the plant did not operate, thus generating zero revenue over the period. Since the plant still incurred fixed expenses, such as staff salary, the plant had a net loss equal to the fixed O&M costs. The plant in the deregulated market operated with a 15%, thus generating revenue of roughly $30 million, and a margin of about 4 million when offset by costs. The plant in the deregulated market generated a large revenue per MWh, but it is greatly reduced due to high fuel costs. The plant in the regulated market is never in a situation where the revenue is higher than the total cost of operation, thus never operates.



			242MW Peaker GE 9FA: Varying Seasonal Dispatch Plant, in a Regulated Market	242MW Peaker GE 9FA: Varying Seasonal Dispatch Plant, in a Non-Regulated Market
MCF	Maximum Capacity Factor (MCF) based on Demand Curve Only	%	55.18	55.18
CF	Actual Capacity Factor (CF)	%	0.00	15.07
REV	Actual Revenue	$	-	30,242,004
FOMC	Fixed O&M Costs	$	629,096	629,096
VOMC	Variable O&M Costs	$	-	622,764
FUELC	Fuel O&M Costs	$	-	24,691,791
VFUELC	Total Fuel and Variable O&M Costs	$	-	25,314,555
TOTOMC	Total O&M Costs	$	629,096	25,943,651
PROFVF	Margin (not factoring Fixed O&M costs)	$	-	4,927,449
PROF	Margin	$	(629,096)	4,298,353
	Actual Revenue per MWh	$/MWh	-	94.69
	Fixed O&M Costs per MWh	$/MWh	-	1.97
	Variable O&M Costs per MWh	$/MWh	-	1.95
	Fuel O&M Costs per MWh	$/MWh	-	77.32
	Total Fuel and Variable O&M Costs per MWh	$/MWh	-	79.27
	Total O&M Costs per MWh	$/MWh	-	81.23
	Margin (not factoring Fixed O&M costs) per MWh	$/MWh	-	15.43
	Margin per MWh	$/MWh	-	13.46

Many of the performance/availability metrics traditionally used are zero for the plant in the regulated market, since the plant in the regulated market did not generate any MWh. This made it difficult to compare the two plants for these metrics. If the market price in the regulated market was just high enough to cause the capacity factor to be greater than zero, the outage factors would be very large, since the ratio of fixed outage hours to small operating hours would be much higher. The equivalent availability factor for the plant in the regulated market was obviously 100%, compared to the 92.2% for the plant in the deregulated market.

Since the total outage hour inputs for both plant models were identical, the capacity factors had the largest influence on traditional availability metrics. The commercial availability metrics were heavily influenced by the market price of power, and also proved to be higher for the deregulated market.

4.3.4 Example 4: 75 MW Pulverized Coal Unit Across Various Markets/Loads

Study Description

This example compares the behaviour for a typical smaller pulverized coal facility in a regulated vs. a deregulated market. The model is based on a small 75 MW pulverized coal plant.

In the interest of accuracy, seasonal demand curves were defined within each market including: 1) Winter: full load with minimum load during nights/weekends 2) Spring/Fall: full load with weekends off 3) Summer: full load with minimum load nights.

Study Objective

The purpose of the example is to illustrate the difference in performance and economics for a smaller pulverized coal facility under regulated and unregulated market conditions. It contains the effects of a seasonally differing demand curves on the smaller pulverized coal plant for each market. It outputs the magnitude of difference of the profitable generation and revenue between plants in different markets.

It is important to note that for this example, the technical inputs for each plant are identical. More specifically, the plants all have the exact same load demand curves, outage hours (planned/scheduled/maintenance), and incremental fuel and variable O&M costs. The only variable that differed between plants included the market type which the plant resided in.

Study Highlights:

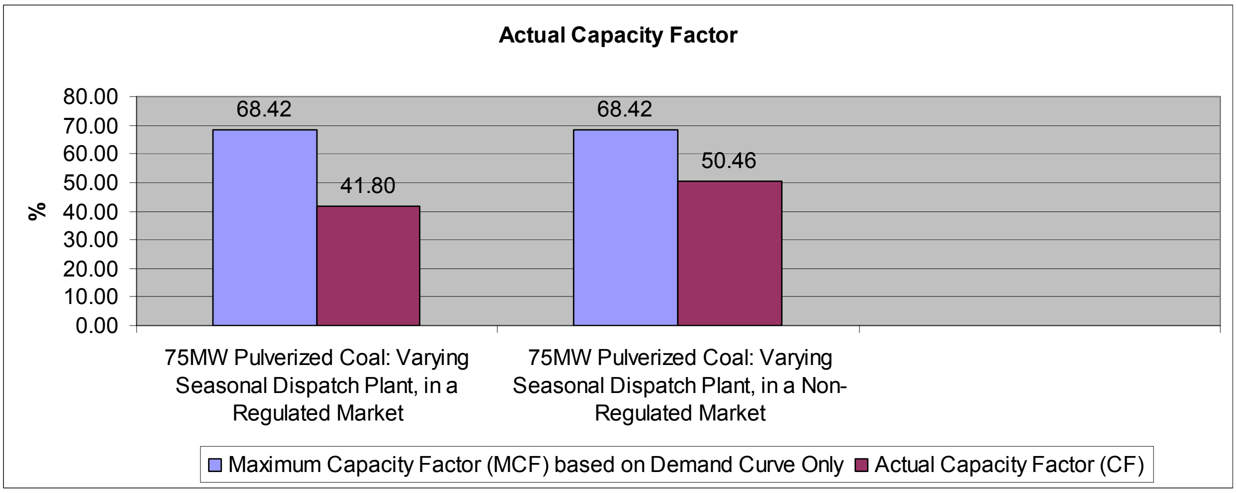
Similar to the other examples and the larger coal plant example, this comparison of a small coal unit proved to show the most prevalent difference present between a regulated and deregulated market was found to be in the capacity factor and the margin. The financial and availability behaviors of the plant in differing markets matched those of the larger coal plant, as expected.

The regulated market operated less, and had a smaller capacity factor at 41.8%, while the deregulated market supported a 50.5% capacity factor. As in the other studies, this was largely due to $/MWh power price difference present in each market.

Table 4-4

4.3.4 Plants Being Investigated

Plant	MW	Technology	Demand	Market	$/ MWH Winter	$/ MWH Spring/Fall	$/ MWH Summer
1	75	Pulverized Coal	Winter: Full Load, Min Load Nights/Weekends Spring/Fall: Weekends Off Summer: Min Load Nights	Regulated	60	50	70
2	75	Pulverized Coal	Winter: Full Load, Min Load Nights/Weekends Spring/Fall: Weekends Off Summer: Min Load Nights	Deregulated	80	100	120



			75MW Pulverized Coal: Varying Seasonal Dispatch Plant, in a Regulated Market	75MW Pulverized Coal: Varying Seasonal Dispatch Plant, in a Non-Regulated Market
MCF	Maximum Capacity Factor (MCF) based on Demand Curve Only	%	68.42	68.42
CF	Actual Capacity Factor (CF)	%	41.80	50.46
REV	Actual Revenue	$	12,338,247	23,353,111
FOMC	Fixed O&M Costs	$	3,060,000	3,060,000
VOMC	Variable O&M Costs	$	554,738	669,697
FUELC	Fuel O&M Costs	$	7,107,678	8,580,609
VFUELC	Total Fuel and Variable O&M Costs	$	7,662,416	9,250,306
TOTOMC	Total O&M Costs	$	10,722,416	12,310,306
PROFVF	Margin (not factoring Fixed O&M costs)	$	4,675,831	14,102,805
PROF	Margin	$	1,615,831	11,042,805
	Actual Revenue per MWh	$/MWh	44.93	70.44
	Fixed O&M Costs per MWh	$/MWh	11.14	9.23
	Variable O&M Costs per MWh	$/MWh	2.02	2.02
	Fuel O&M Costs per MWh	$/MWh	25.88	25.88
	Total Fuel and Variable O&M Costs per MWh	$/MWh	27.90	27.90
	Total O&M Costs per MWh	$/MWh	39.04	37.13
	Margin (not factoring Fixed O&M costs) per MWh	$/MWh	17.03	42.54
	Margin per MWh	$/MWh	5.88	33.31

The largest difference between the two plants resides in the generated revenue. The deregulated plant generated about $23.4 million, while the regulated plant generated roughly $12.3 million. This higher revenue for the deregulated market is due to the difference in capacity factor present caused by the different market prices of power for each market. This revenue deviation then follows through causing the margins to be dissimilar as well. The cost of coal used by this model was $2/MBtu.

When investigating the comparison of traditional availability output metrics, it was found that they were similar, but the forced outage rates for the deregulated market were slightly lower, due to the increased generation over the period.

When comparing the commercial availabilities between plants, as expected the small coal plant placed in a deregulated market has a higher commercial availability, since it was in profitable generating conditions more often throughout the period.

Not surprisingly, the smaller coal plant financial and availability metric differences between markets paralleled those of the larger coal plant. The financial revenues and operating margins were obviously on a much smaller scale. Commercial availability metrics proved to be slightly higher, and traditional outage rates slightly lower for the larger plants.

Table 4-5

4.3.5 Plants Being Investigated

Plant	MW	Technology	Demand	Market	$/ MWH Winter	Spring/Fall	Summer
1	800	Pulverized Coal	Baseload Plant	Regulated	60	50	70
2	800	Pulverized Coal	Baseload w/Nightly Load Following	Regulated	60	50	70
3	800	Pulverized Coal	Daily Full Load, Min Load Night and Weekend	Regulated	60	50	70
4	75	Pulverized Coal	Winter: Full Load, Min Load Nights/Weekends Spring/Fall: Weekends Off Summer: Min Load Nights	Regulated	60	50	70
5	300	Oil-Fired Steam	Winter: Full Load, Min Load Nights/Weekends Spring/Fall: Weekends Off Summer: Min Load Nights	Regulated	60	50	70
6	242	GE 9FA Peaker	Winter: Daily Peaking, Nights Weekends Off Spring/Fall: Reserved Shutdown Summer: Twice Daily Peak, Morning Afternoon	Regulated	60	50	70

4.3.5 Example 5: 75 MW Pulverized Coal Unit Across Various Markets/Loads

Study Description

This example provides a side-by-side comparison for the behavior for various facilities in a regulated market. The technologies being investigated in this example include large and small pulverized coal, oil-fired steam, and peakers.

For the plants that typically have pronounced seasonal shifts, separate seasonal demand curves were applied.

Study Objective

This example investigates the differences across a broad array of technologies in a regulated market. It illustrates the differences in magnitude of capacity and margin for each of these types of plants

It is important to note that for this example, the plants reside in identical market conditions. The plants all differ in technologies, operating and fuel costs, load curves, and outage durations typical for the technologies.

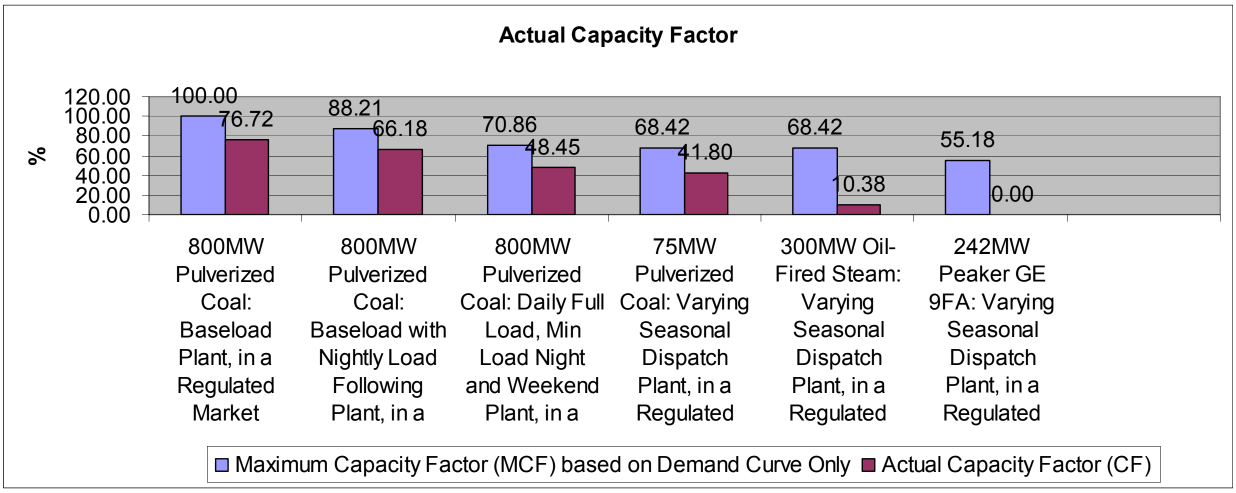
Study Highlights

There were many differences exposed in this example by the output reports that the tool generates. The capacity factors varied across a large range from the peaker's 0% to the large baseloaded coal plant's 76.7% capacity factor. Since the market definitions were the same for all plants, the differences in capacity factor were primarily caused by economics surrounding demand profiles and fuel prices. The plants with the high fuel prices had the lowest capacity factors, in this order from highest CF to lowest: large coal (49-76%), small coal (42%), oil (10%), natural gas peaker (0%). This is due to the higher fuel costs reducing the amount of profitable operating time by reducing the duration of time when revenues surpassed the total cost of operation.

Revenues followed the same order from highest to lowest, primarily influenced by capacity factors: large coal ($144-211 million), small coal ($ 12 million), oil ($15 million), natural gas peaker ($0 million).

When factoring in the costs of operation, including previously discussed fuel costs, the margin achieved almost parallels the revenue, switching oil and gas: large coal ($54-70 million), small coal ($2 million), natural gas peaker ($-0.6 million), and oil ($-0.7 million). Negative margin is seen due to the fact that even when the plants were not operating, they were still incurring fixed costs such as salary.

When reviewing the margin on a per MWh basis, the same order applies: large coal ($14-16 per MBtu), small coal ($6 per MBtu), oil (-$3 per MBtu). (The natural gas peaker did not supply any MWh, so no $/MWh was calculated.) Interestingly, although the baseloaded large coal plant generated



more revenue than the same large coal plant running daily full load with minimum loads nights and weekends, it did not generate more margin per MWh. The plant that came down to minimum nights and weekends generated $2 per MWh more than the baseloaded plant.

When reviewing the revenue on a per MWh basis, the order actually reverses: oil ($57 per MBtu), small coal ($45 per MBtu), large coal ($39-43 per MBtu). (The natural gas peaker did not supply any MWh, so no $/MWh was calculated.)

Due to the lower capacity factor, the oil-fired steam plant had higher traditional availability (EAF), and a higher rate of forced outage hours to hours actually generating. This negatively impacts many of the traditional and commercial availability metrics.

According to this study, the largest capacity coal plant with the lowest capacity factor would make the most margin per MWh.

4.3.6 Example 6: Differing Facilities Across Multiple Loads in a Deregulated Market

Study Description

This example provides a side-by-side comparison for the behavior for various facilities in a deregulated market. The technologies being investigated in this example include large and small pulverized coal, oil-fired steam, and peakers.

For the plants that typically have pronounced seasonal shifts, separate seasonal demand curves were applied.

Study Objective

This example compares the same plants from example 5, but immersed in a deregulated market.

It is important to note that the plants in this example all differ in technologies, operating and fuel costs, load curves, outage durations, and market conditions that they reside in.

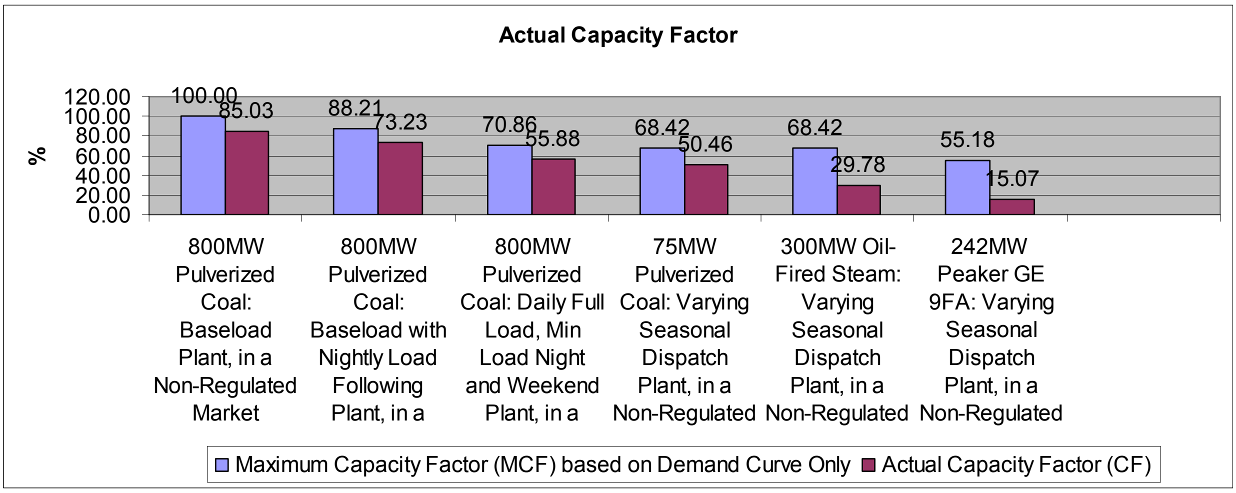
Study Highlights

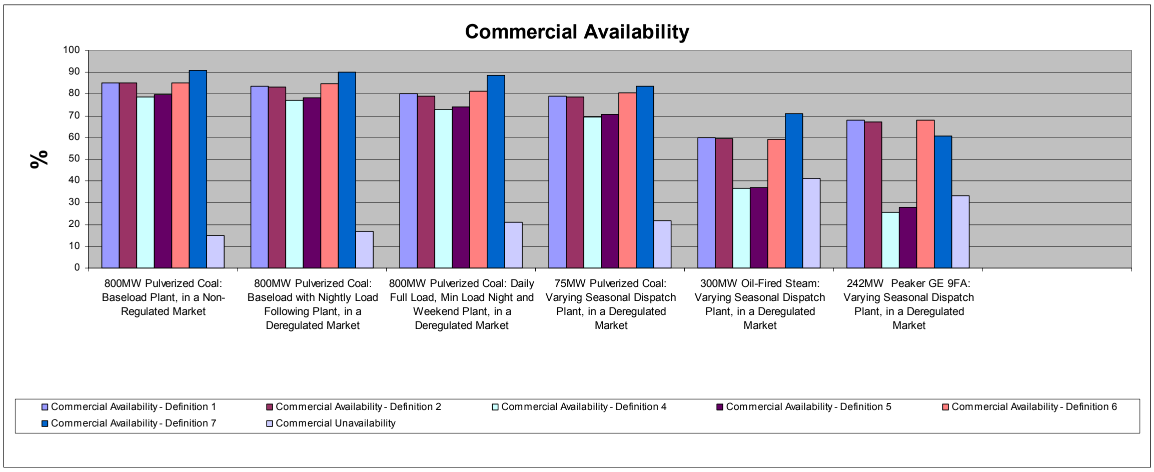
Many of the differences paralleled example 5, for the regulated market. The biggest difference, is that the price of power was high enough for the peaker to operate, although infrequently, and the rest of the plants to operate at a slightly higher capacity factor. The capacity factors varied across a large range from the peaker's 15% to the large baseloaded coal plant's 85% capacity factor. Since the market definitions were the same for all plants, the differences in capacity factor were also primarily caused by economics surrounding demand profiles and fuel prices. The plants with the high fuel prices had the lowest capacity factors, in this order from highest CF to lowest: large coal (56-85%), small coal (51%), oil (30%), natural gas peaker (15%). This is due to the higher fuel costs reducing the amount of profitable operating time by reducing the duration of time when revenues surpassed the total cost of operation.

Table 4-6

4.3.6 Plants Being Investigated

Plant	MW	Technology	Demand	Market	$/ MWH Winter	$/ MWH Spring/Fall	$/ MWH Summer
1	800	Pulverized Coal	Baseload Plant	Deregulated	80	100	1200
2	800	Pulverized Coal	Baseload w/Nightly Load Following	Deregulated	80	100	120
3	800	Pulverized Coal	Daily Full Load, Min Load Night and Weekend	Deregulated	80	100	120
4	75	Pulverized Coal	Winter: Full Load, Min Load Nights/Weekends Spring/Fall: Weekends Off Summer: Min Load Nights	Deregulated	60	100	120
5	300	Oil-Fired Steam	Winter: Full Load, Min Load Nights/Weekends Spring/Fall: Weekends Off Summer: Min Load Nights	Deregulated	60	100	120
6	242	GE 9FA Peaker	Winter: Daily Peaking, Nights Weekends Off Spring/Fall: Reserved Shutdown Summer: Twice Daily Peak, Morning Afternoon	Deregulated	80	100	120





Revenues were much higher in the deregulated market when compared to the regulated market. Revenues followed the same order from highest to lowest, primarily influenced by capacity factors: large coal ($273-386 million), small coal ($ 23 million), oil ($62 million), natural gas peaker ($30 million).

When factoring in the costs of operation, including previously discussed fuel costs, the margin achieved parallels the revenue with one difference, the oil and small coal flip-flop: l large coal ($171-238 million), oil ($21 million), small coal ($11 million), natural gas peaker ($4 million).

The same order applies for the margin on a per MWh basis: large coal ($40-44 per MBtu), small coal ($33 per MBtu), oil ($27 per MBtu), natural gas peaker ($14 per MBtu). Interestingly, although the baseloaded large coal plant generated more revenue than the same large coal plant running daily full load with minimum loads nights and weekends, it did not generate more margin per MWh. The plant that came down to minimum nights and weekends generated $3.6 per MWh more than the baseloaded plant.

The order actually reverses for the revenue on a per MWh basis: natural gas peaker ($95 per MBtu), oil ($79 per MBtu), small coal ($70 per MBtu), large coal ($65-70 per MBtu). The margin per MWh reverses the order when costs of fuel are factored in.

Due to the lower capacity factors, the natural gas peaker had higher traditional availability (EAF), and the natural gas and oil-fired plants had higher forced outage rates. This negatively impacts many of the traditional and commercial availability metrics, as seen in the following chart of the commercial availabilities.

As seen in the similar regulated market example 5, the largest capacity coal plant with the lowest capacity factor would make the most money per MWh in a deregulated market as well.

4.3.7 Example 7: 800 MW Pulverized Coal Across Various Outage Magnitudes/Markets

Study Description

This example compares a large baseloaded pulverized coal plant in both a regulated and deregulated market across varying forced and scheduled outage magnitudes. This example is based on a large 800 MW pulverized coal fired unit.

The same large coal plant is subjected to differing high forced and scheduled outage magnitude combinations.

Study Objective

This example illustrates how differing forced and planned outage hour levels effects a large baseloaded coal plant. It investigates the differing effects of these outage strategies in regulated and

deregulated markets. To contrast, one plant has double the normal forced outage hours and normal scheduled outage hours, another has normal scheduled outage hours and double scheduled outage hours, and one plant has both double scheduled and forced outage hours.

Table 4-7

4.3.7 Plants Being Investigated

Plant	MW	Technology	Demand	Market	$/ MWH Winter	$/ MWH Spring/Fall	$/ MWH Summer	Planned Outage	Forced Outage
1	800	Pulverized Coal	Baseload Plant	Regulated	60	50	70	750 – Avg.	251 – Avg.
2	800	Pulverized Coal	Baseload Plant	Regulated	60	50	70	750 – Avg.	502 – Avg.
3	800	Pulverized Coal	Baseload Plant	Regulated	60	50	70	1500 – High	251 – Avg.
4	800	Pulverized Coal	Baseload Plant	Regulated	60	50	70	1500 – High	502 – Avg.
5	800	Pulverized Coal	Baseload Plant	Deregulated	80	100	120	750 – Avg.	251 – Avg.
6	800	Pulverized Coal	Baseload Plant	Deregulated	80	100	120	750 – Avg.	502 – Avg.
7	800	Pulverized Coal	Baseload Plant	Deregulated	80	100	120	1500 – High	251 – Avg.
8	800	Pulverized Coal	Baseload Plant	Deregulated	80	100	120	1500 – High	502 – Avg.

It is important to note that for this example, each unit is presumed to have “identical” technical performance. Specifically, each unit has the same incremental costs of production including fuel costs and variable O&M are also held constant across plants. The major difference between plants includes the planned and forced outage hours encountered. Differing combinations of high and typical planned and forced outage hours are investigated. This investigation models identical plants within regulated and deregulated markets

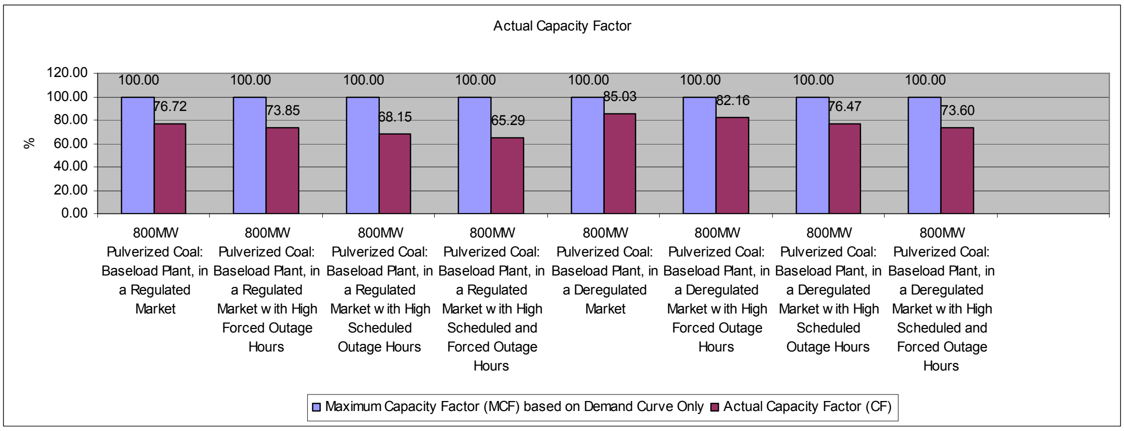
Study Highlights

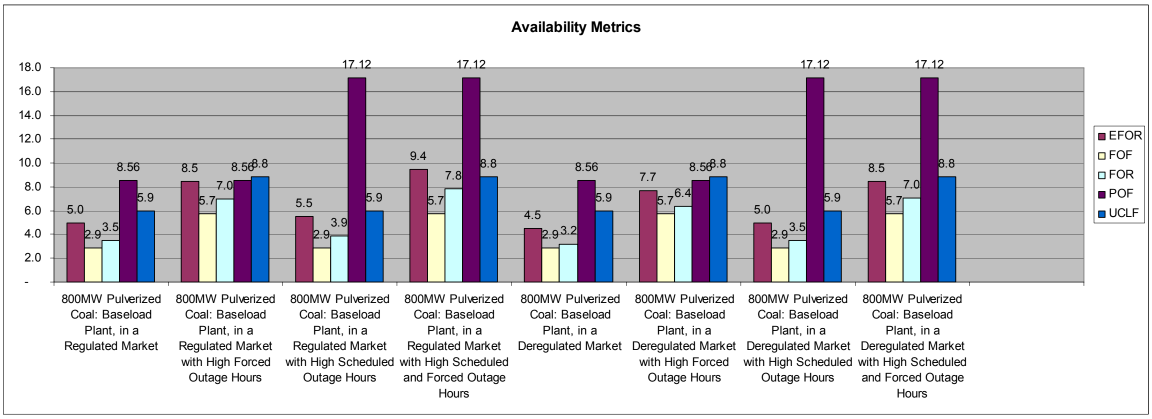
The largest difference across the large coal plant in different markets occurs in the capacity factor. The capacity factor for a plant in a deregulated market is about 11-13% higher than the same plant in a regulated market, as seen in the other studies.

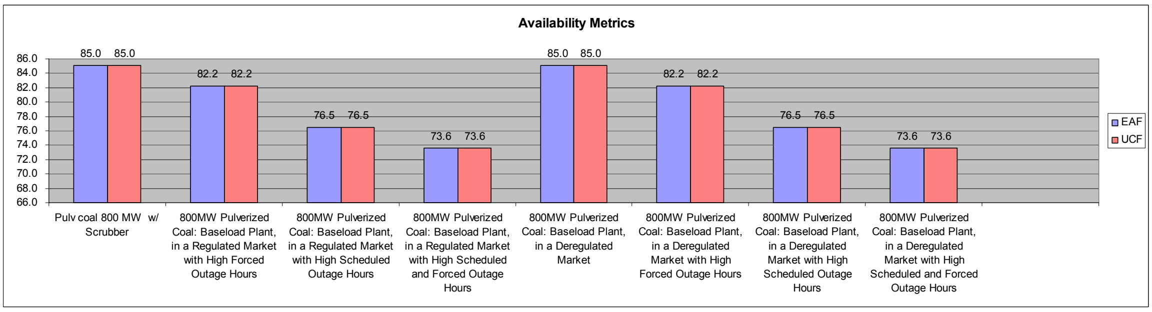
This is true across all plants even when considering the differing outage strategies, due to the fact that the price of power is higher in a deregulated market, thus allowing for more windows of time in which the revenue exceeds the costs, thus ensuring generation during those times.

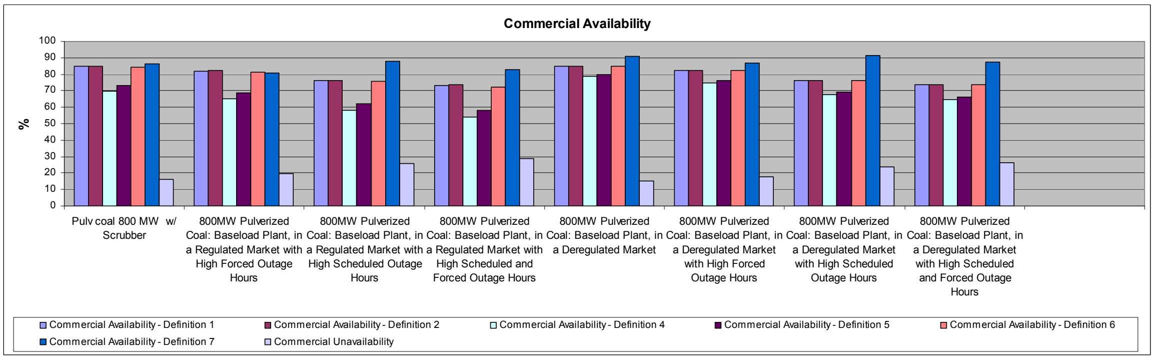
The capacity factors within each market across the differing outage strategies differed by about 11%. The higher capacity factor was seen for the plants with less outage hours, obviously. When comparing the effects on the capacity factor between forced outage and scheduled outage hours, it was found that the high scheduled outage hours had a larger effect on the capacity factor than the high forced outage hours. This was due to the magnitude of the increase for a high scheduled outage vs. the high forced outage: the scheduled outage increase in hours was much larger than the forced outage hour increase for this example.

Increased generation leads to increased revenue, thus revenue was higher in the deregulated market. The deregulated market plants had roughly 84% more revenue than in the regulated market. Total costs for the plant in the deregulated market were only ~10% higher than in the regulated market mostly due to increased generation.









Since the revenues are dramatically higher, but the costs are still comparable, the margins are also much higher in the deregulated market (~215% higher margin in the deregulated market). When comparing the plants' margin on a dollar per MWh basis, the deregulated market still generates 178-185% more margin per MWh than the plants in the regulated market.

When comparing across differing outage strategies, the plants with less outage hours generate more MWh, thus have higher revenues and margins. Revenue per MWh is very similar, despite the differences in outage hours between plants. Margin per MWh shows a slight difference, spanning a small range of $0.30 per MWh difference. The plants with less outage hours exhibit on the higher end of margin per MWh.

When comparing the traditional availability metrics for a large coal plant, it was found that the Equivalent Availability Factor (EAF) was identical for the same plant in both a deregulated and regulated market. The EAF reduced as the forced and scheduled outage hours increased, spanning across a range of 74-85%. Forced Outage Factor (FOF) doubled, when forced outage hours were doubled.

The same thing was seen in Planned Outage Factor (POF), when planned outage hours were doubled. Equivalent Forced Outage Rates and Forced Outage Rates increased as outage hours increased, and were lower in the deregulated market, as expected.

Commercial availability metrics were lower in the regulated market also, and decreased as outage hours increased. This commercial availability difference seen across markets was masked in the traditional EAF.

4.4 Generalized Observations

While the examples are far from inclusive for consideration of all the variables that impact either technical or commercial availability, it is possible to draw on the effort to highlight a few key points.

There is no consistent relationship between technical and commercial availability factors.

- This reality is rooted in the fact that commercial availability metrics are largely driven by when plants are "in the money." Economic considerations (combination of market price and cost of production), as well as regional market characteristics (shape of load demand, technology stack, etc.) will differ from region to region.

Differences in commercial and technical availability metrics will be more significant for deregulated vs. regulated markets.

- Typically, in deregulated market, the price of power is much higher during periods of high demand thus makes the window of time larger in which the revenue potentially generated by the plant exceeds the costs to generate those MWh. The plant is "in the money" more often, thus operates more and has higher capacity factors.

Differing facility types will have different impacts on technical vs. commercial availability largely due to inherent differences in the cost of production.

- The major differentiating factor seemed to be the fuel costs and the fact that the higher fuel cost plants less frequently reach the threshold for generating positive margin. In a commercial sense, these units can generate large profits over short periods of operation (high margin/MWh) but lower overall margins per annum per installed capacity (MW) vs. baseload units.

Differing outage strategies impact both technical and commercial metrics.

- When the same plant has a more aggressive outage plan, and spends more hours in outage, whether it be forced or scheduled, it has a lower capacity factor and thus generates less revenue. Since it generates less revenue there is less margin. In this case, one can see that changes in traditional availability do correlate with changes in commercial availability; both decrease as outage hours increase.

It is interesting to postulate on ways to leverage the PGP model to compare plants across regions/markets. While the model directly provides a means to identify relationships between commercial and traditional availability for a given region, technology, fuel type, it is not clear as to the best way to compare performance across markets, or in other words, to "translate" performance measures across markets/regions.

It is clear that commercial realities (i.e., margin or profit potential) will define the *economic* incentives associated with different levels of technical performance. What is not clear is how to "predict" optimal performance targets across regions [i.e., defining the optimal level of investment that will maximize margin within the context of the market]. One possible method to evaluate this issue could be as follows:

- Apply the PGP model to calculate differential revenue or margin for technology of interest for each region of interest. This provides the data needed to approximate "value" of either increasing/decreasing availability and commercial availability

- Identify incremental fixed/variable costs to be invested to realize a step change in performance; please note that the PGP model does not provide a means to calculate or predict the underlying cost differences but does provide a way to see how dispatch/profitability would be impacted by changes in such costs and associated performance impacts.

- Assess "where" cost/benefits suggest technical performance are balanced for each region based on assumed level of benefits and incremental investment.

- Apply PGP model to compare traditional and commercial performance indicators across regions, with each at the presumed economic optimal point. This exercise would provide the approximate "offset" in commercial availability targets between regions based on market/economics.

- Performance of plants within regions could be benchmarked against region-specific targets; results could be aggregated by focusing of variance from best of class performers, in terms of lost margin potential.

Clearly, more work is required by the PGP to evaluate the validity/value of benchmarking processes such as the above. It is equally clear, however, that given the continued state of the ESI (different markets, different regulations, different technologies, etc.) that there is immense value in pursuing the objective of defining means to benchmark unit performance in terms of commercial potential. This issue will be further evaluated in the next 3-year period of PGP activities.

5. How Does it Work?

5.1 General Organization

This section is developed to supplement the brief overview with more information and details on how the tool actually works. It focuses on how one would actually use the model, and gives them a general idea of the look and feel of the model and its layout. It will dive into the key elements, and also expose some of the options and outputs from the report.

The interface for the PGP model is laid out in an organization similar to Figure 5-1, with the following sections

- An **INPUT** area designated to input the factors of the model
- A **MODEL** area where the model's calculations are exposed
- An **OUTPUT** area to display the output trends and tables for comparison
- A **CALCULATIONS** area to display the calculations for each investigation

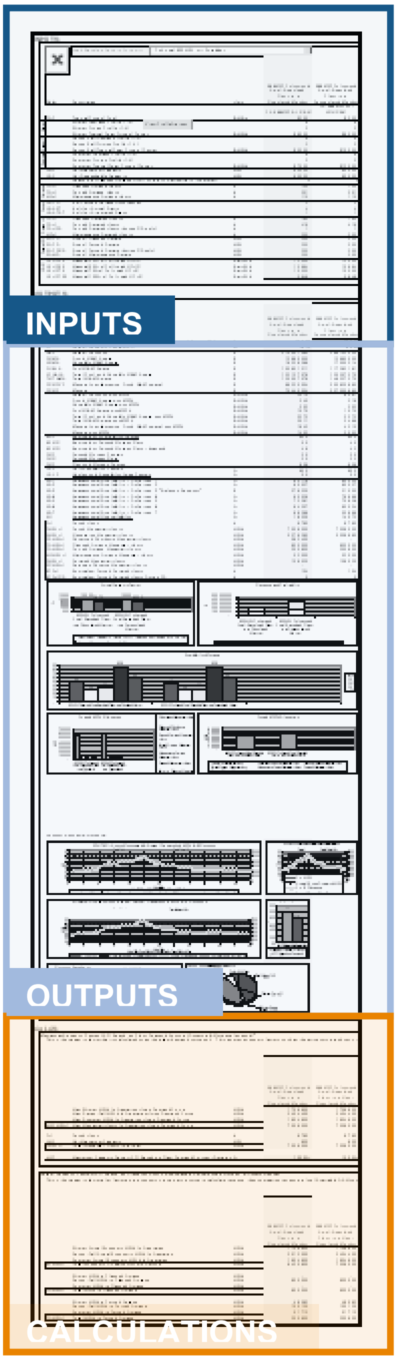
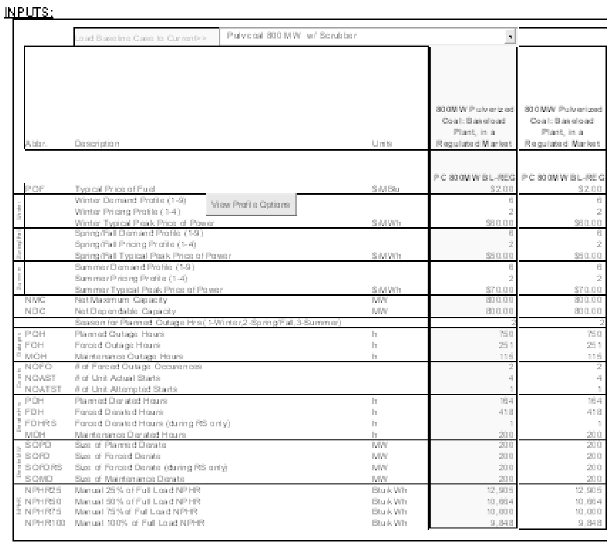


Figure 5-1
Model PGP Layout



INPUTS:

Load Baseline Case to Current>> | Pulvcoal 800 MW w/ Scrubber

View Profile Options

Abbr.	Description	Units	800MW Pulverized Coal: Baseload Plant, in a Regulated Market	800 MW Pulverized Coal: Baseload Plant, in a Regulated Market
			PC 800MW BL-REG	PC 800MW BL-REG
POF	Typical Price of Fuel	$/MBtu	$2.00	$2.00
	Winter Demand Profile (1-9)		6	6
	Winter Pricing Profile (1-4)		2	2
	Winter Typical Peak Price of Power	$/MWh	$60.00	$60.00
	Spring/Fall Demand Profile (1-9)		6	6
	Spring/Fall Pricing Profile (1-4)		2	2
	Spring/Fall Typical Peak Price of Power	$/MWh	$50.00	$50.00
	Summer Demand Profile (1-9)		6	6
	Summer Pricing Profile (1-4)		2	2
	Summer Typical Peak Price of Power	$/MWh	$70.00	$70.00
NMC	Net Maximum Capacity	MW	800.00	800.00
NDC	Net Dependable Capacity	MW	800.00	800.00
	Season for Planned Outage Hrs(1-Winter,2-Spring/Fall,3-Summer)		2	2
POH	Planned Outage Hours	h	750	750
FOH	Forced Outage Hours	h	251	251
MOH	Maintenance Outage Hours	h	115	115
NOFO	# of Forced Outage Occurrences		2	2
NOAST	# of Unit Actual Starts		4	4
NOATST	# of Unit Attempted Starts		1	1
PDH	Planned Derated Hours	h	164	164
FDH	Forced Derated Hours	h	418	418
FDHRS	Forced Derated Hours (during RS only)	h	1	1
MDH	Maintenance Derated Hours	h	200	200
SOPD	Size of Planned Derate	MW	200	200
SOFD	Size of Forced Derate	MW	200	200
SOFDRS	Size of Forced Derate (during RS only)	MW	200	200
SOMD	Size of Maintenance Derate	MW	200	200
NPHR25	Manual 25% of Full Load NPHR	Btu/kWh	12,905	12,905
NPHR50	Manual 50% of Full Load NPHR	Btu/kWh	10,664	10,664
NPHR75	Manual 75% of Full Load NPHR	Btu/kWh	10,000	10,000
NPHR100	Manual 100% of Full Load NPHR	Btu/kWh	9,848	9,848

Figure 5-2
Input Screen

Generally speaking, within each of the areas there is a column for each of the plants being compared. The first yellow highlighted column is the current plant that is being investigated. Once the inputs are set, and the user is finished configuring the current plant, a button is pushed which replicates the contents of the current plant column over to a new column to the right of the current column for future reference and comparison. As each column is added to the model, the comparison presents itself in the form of a table with one column per plant for easy comparison. At any point, a new plant can quickly be added or deleted. Also, when a new plant is added, the new plant is added to the set of output trends for comparison as well.

5.2 Adding Plants

There are several ways to add plants to the PGP model for comparison, each varying in difficulty from simply clicking a button, to choosing a plant from a drop down, to data entry of all inputs for each of the plants. Each of these methods varies in difficulty and flexibility.

5.2.1 Pre-Populated Case Studies

The easiest way to populate a comparison is to view the pre-populated case studies that explore several groupings of plants. By clicking a button, several differing plants are loaded to the PGP model and output comparisons generated for analysis. The current case studies within the model were chosen to represent various plant groupings in various scenarios for some common plants.

The case studies can be accessed on the main page, by clicking a button specified for each example. The following is a screenshot of the main page for the calculator containing hyperlink buttons to example case studies. When the button next to the example description is clicked, the model serves up an example set of plants that has been pre-populated. Each example set contains a group of plants to be compared to each other. Each example examines the comparison between plants in differing markets, demand curves, and technologies applied. They contain differing analysis investigating comparisons of both large and small coal-fired, oil-fired, and peakers in regulated and deregulated markets with differing demand curves. Section 5 contains a breakdown of each of the examples currently populated in the tool. When the button for any of the examples is clicked, it takes the user to a tab that displays all of the plants being compared for the example

STUDY DESCRIPTION:

This study compares a 75MW pulverized coal plant in both a regulated and unregulated market.

CONCLUSIONS:

The 75MW coal plant in a non-regulated market operates at roughly ~9% higher capacity factor than the same plant in a regulated market, and thus generates about double the revenue. This translates to about 11x the margin. The outage metrics are worse in the regulated market, since there is less time in the money to spread the same outage and derated hours over.

PLANTS BEING INVESTIGATED:

Plant1 - This plant is a 75MW pulverized coal-fired unit, in a regulated market.
Plant2 - This plant is a 75MW pulverized coal-fired unit, in a non-regulated market.

INPUTS:

Load Baseline Case to Current>> | Pulv coal 75 MW w/o Scrubber

	Abbr.	Description		Units	75MW Pulverized Coal: Varying Seasonal Dispatch Plant, in a Regulated Market	75MW Pulverized Coal: Varying Seasonal Dispatch Plant, in a Non-Regulated Market
					PC 75MW VS-REG	PC 75MW VS-NONREG
	POF	Typical Price of Fuel		$/MBtu	$2.40	$2.40
Winter		Winter Demand Profile (1-9)	View Profile Options		1	1
		Winter Pricing Profile (1-4)			2	2
		Winter Typical Peak Price of Power		$/MWh	$60.00	$60.00

5.2.2. Using the Sample Library of Plants

Another easy way to add an individual plant to the current model is to use a dropdown that has been made available that is populated with a library of plants with differing situations. When a new plant is selected in the dropdown, the full set of inputs for the chosen plant is populated by the dropdown selection. This list contains pulverized coal plants, circulating fluidized bed (CFB's), oil-fired steam, and simple cycle CT plants across a broad range of MW. This drop down can also be used to save time by initially populating the input set for a particular plant before making any necessary edits. If the exact plant is not found within the list, then the closest match can be selected and adjusted to fit the user's needs.

5.2.3 Creating Custom Plants for Comparison

Some users will want to custom define their own plants for comparison. This flexibility is present in the tool. The user can manually populate the inputs for any plant, or edit the inputs to a plant generated by the auto-populating features. The input section for the model occurs on the "Scenarios" tab as seen in the following screenshot. The inputs for the model have purposefully been reduced to a minimum. This is to make the act of populating the model manageable.

Typical Price of Fuel:

This is to populated with the typical price of the primary fuel for the unit. In the current version of the model, the fuel price is entered in $US/MBtu. The current case studies define the price of coal as $2 per MBtu (i.e., roughly 47 Euro/tonne), oil as $5 per MBtu, and natural gas as $7 per MBtu.

Demand Profile Selection:

The next section of inputs defines the market and demand for the plants. The goal of this section is to define how to consider how changes in the market price of power impact the demand for the plant in question. The authors felt defining market and demand curves for each season achieved a good balance between model complexity and simulation of the dynamic plant environment. The seasons were separated in to Summer, Winter, and Spring/Fall. Spring and Fall were combined due to the similarities temperatures, etc.

The following assumptions were used to develop this section of the model.

- A curve is used to model each season to best represent the dynamic nature across a typical day.

- Potential differences between weekday and weekend day demands and market price vary can be modelled via use of separate weekday and weekend day curve shapes.

- Pre-built selections of both market price and demand curves are provided in the model to facilitate the identification of the market and demand for the plants. These curves are referred to as “profiles” within the input section of the model.

The demand profile selected must match the shape of the plant’s MW throughout a typical weekday and weekend day during that season as seen in Figure 7. The first 24 hours on the X-axis are representative of a typical weekday, and hours 25-48 on the X-axis represent the typical weekend day. The Y-axis represents the magnitude of MW load for the plant across those hours, 0.0 to 1.0 representing a range from offline to Net Dependable Capacity (NDC). If the NDC is 500MW, then the 1.0 = 500MW, and 0.5=250MW, and so on. A full collection of the available profiles can be seen in Appendix C of this paper.

Each of the different demand profiles represent a large percentage of the differing demands that most plants will see, thus it should be easy to find the desired demand profile. Click on the “View Profile Options” button to view the profile selections within the PGP model.

The price profiles are very similar to the demand profiles, containing the price of power for a typical weekday and weekend day. Magnitude of price (Y-axis of the curve 0.0-1.0) is a factor applied to the “Typical Price of Power” seen in the INPUT section rows for each season. Therefore, if the typical peak price of power is $75, then the 1.0 = $75, and 0.5=$37.50, and so on. A full collection of the available profiles can be seen in Appendix C of this paper.

Net Maximum Capacity:

The next input encountered is the Net Maximum Capacity which is the **maximum** capacity the plant can hit, excluding seasonal derating.

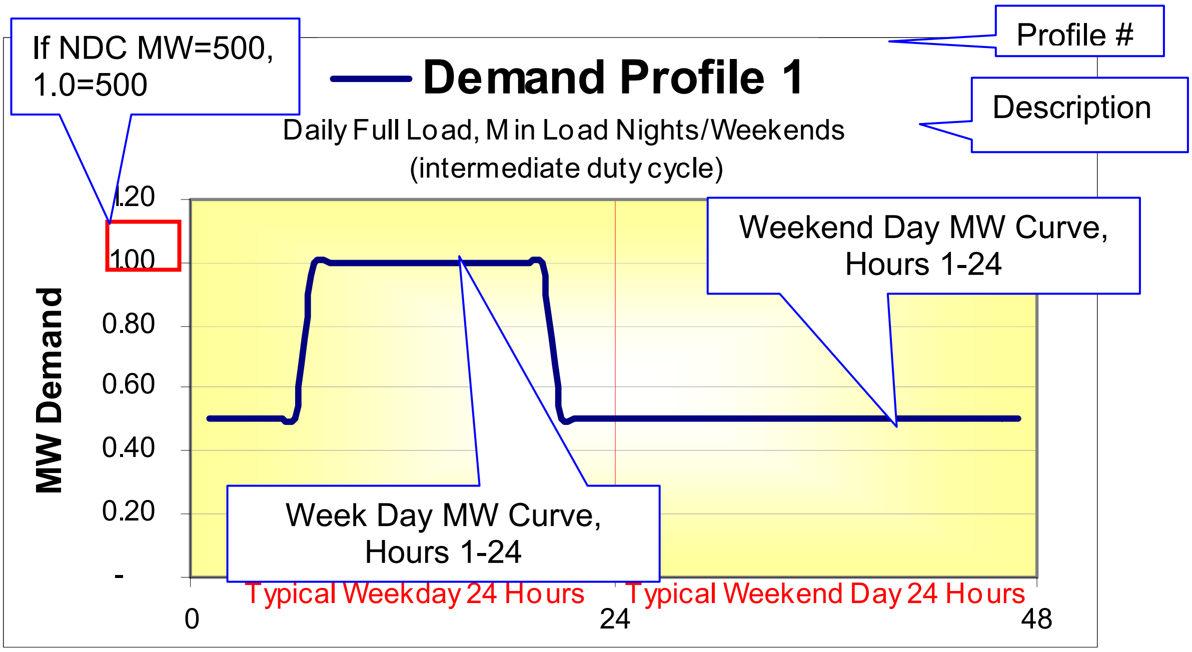
Net Dependable Capacity:

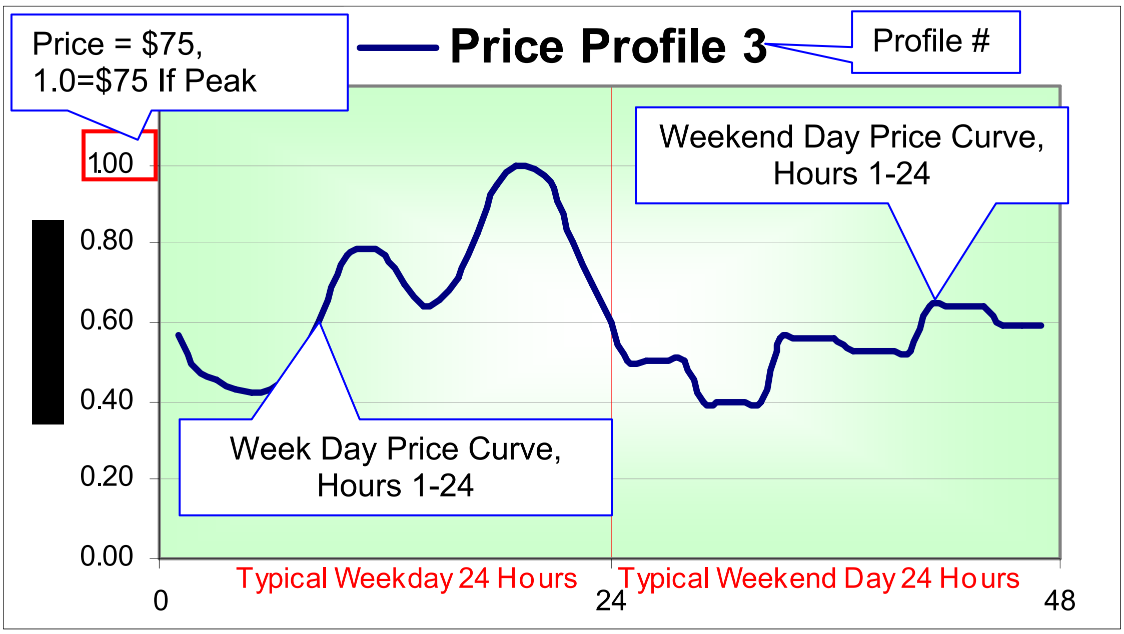
The Net Maximum Capacity is the capacity that the plant is able to regularly maintain at safe levels considering seasonal derates.

The next portion of the INPUTS is the section in which all outage information is collected.

Season for Planned Outage Hrs (1-Winter,2-Spring/Fall,3-Summer):

This input defines which season the outages and derates will be applied. This is necessary for the model, since it is not likely that a plant will schedule a planned outage during a time when the market price and profitability is highest. This allows the user to identify the season for which the planned outage hours will be applied for a plant. This is useful for those plants such as peakers that may never plan outages during the summer months.


If NDC MW=500,
1.0=500
Demand Profile 1
Daily Full Load, Min Load Nights/Weekends
(intermediate duty cycle)
Profile #
Description
Weekend Day MW Curve,
Hours 1-24
Week Day MW Curve,
Hours 1-24
MW Demand
1.20
1.00
0.80
0.60
0.40
0.20
-
Typical Weekday 24 Hours
Typical Weekend Day 24 Hours
0
24
48


Price = $75,
1.0=$75 If Peak
Price Profile 3
Profile #
Weekend Day Price Curve,
Hours 1-24
Week Day Price Curve,
Hours 1-24
[redacted]
1.00
0.80
0.60
0.40
0.20
0.00
Typical Weekday 24 Hours
Typical Weekend Day 24 Hours
0
24
48

Planned Outage Hours (h):

The Planned Outage Hours include the sum of all hours experienced during Planned Outages (PO) and Planned Outage Extensions(SE of PO).

Forced Outage Hours (h):

The Forced Outage Hours include the sum of all hours experienced during Forced Outages.

Maintenance Outage Hours (h):

The Maintenance Outage Hours include the sum of all hours experienced during all Maintenance Outages.

Number of Forced Outage Occurrences:

This is a count of all forced outage occurrences used primarily in the calculation of $EFOR_D$ (equivalent forced outage rate during periods of demand).

Number of Unit Actual Starts:

This is a count of all actual successful unit starts throughout a year also used primarily in the calculation of $EFOR_D$ (equivalent forced outage rate during periods of demand).

Number of Unit Attempted Starts:

This is a count of all attempted unit starts throughout a year also used primarily in the calculation of $EFOR_D$ (equivalent forced outage rate during periods of demand).

The next portion of the INPUTS is the section in which all derate information is collected.

Planned Derate Hours (h):

This is a sum of all hours experienced during Planned Derates.

Forced Derate Hours (h):

This is a sum of all hours experienced during Forced Derates.

Forced Derate Hours (during RS only) (h):

This is a sum of all hours experienced during Forced Derates during reserved shutdown only.

Maintenance Derate Hours (h):

This is a sum of all hours experienced during Maintenance Derates.

Size of Planned Derate (MW):

This is the average size (in MW) of Planned Derated hours.

Size of Forced Derate (MW):

This is the average size (in MW) of Forced Derated hours.

Size of Forced Derate (MW):

This is the average size (in MW) of Forced Derated hours during reserved shutdown only.

Size of Maintenance Derate (MW):

This is the average size (in MW) of Maintenance Derated hours.

The next portion of the INPUTS is the section in which all performance Net Plant Heat Rate information is collected across the load range for the plants.

5.3.1 Model Calculations

Following the OUTPUTS section of the "Scenarios" tab is the CALCULATIONS section which outlines all of the calculations used within the model. As the following screenshot illustrates, the calculation is listed with a text description and a formula for each calculation, as well as a list of the inputs and key intermediate calculations. The complete list of calculations and their formulas can be investigated in Appendix A.

Figure 5-3

Model Calculations Example Screenshot

Actual Revenue (REV)[3]

This is the total revenue calculated using the economically dispatched revenue and considering outages and derates.

$$REV = \max\ econ\ rev - planned\ outage\ rev\ lost - forced\ outage\ rev\ lost - \text{maint}\ outage\ rev\ lost - derate\ rev\ lost$$

$$= MAXREV - POREV - FOREV - MOREV - DRREV$$

			75MW Pulverized Coal: Varying Seasonal Dispatch Plant, in a Regulated Market	75MW Pulverized Coal: Varying Seasonal Dispatch Plant, in a Non-Regulated Market
MAXREV	Max Economical Revenue Dispatched	$	16,215,555	29,521,575
	Winter Revenue Lost Due to Planned Outages	$	-	-
	Spring-Fall Revenue Lost Due to Planned Outages	$	1,663,594	2,849,438
	Summer Revenue Lost Due to Planned Outages	$	-	-
POREV	Revenue Lost Due to Planned Outages	$	1,663,594	2,849,438
	Winter Revenue Lost Due to Forced Outages	$	260,528	260,528
	Spring-Fall Revenue Lost Due to Forced Outages	$	461,856	791,077
	Summer Revenue Lost Due to Forced Outages	$	282,516	455,044
FOREV	Revenue Lost Due to Forced Outages	$	1,004,900	1,506,649
	Winter Revenue Lost Due to Maintenance Outages	$	154,260	154,260
	Spring-Fall Revenue Lost Due to Maintenance Outages	$	273,467	468,401
	Summer Revenue Lost Due to Maintenance Outages	$	167,279	269,434
MOREV	Revenue Lost Due to Maintenance Outages	$	595,007	892,095
	Winter Revenue Lost Due to Derate	$	159,134	159,134
	Spring-Fall Revenue Lost Due to Derate	$	282,108	483,201
	Summer Revenue Lost Due to Derate	$	172,565	277,947
DRREV	Revenue Lost Due to Derate	$	613,807	920,283
	Revenue Lost Due to Planned Outages	$	1,663,594	2,849,438
	Revenue Lost Due to Forced Outages	$	1,004,900	1,506,649
	Revenue Lost Due to Maintenance Outages	$	595,007	892,095
	Revenue Lost Due to Derates	$	613,807	920,283
	Total Revenue Lost Due to Outages/Derates	$	3,877,308	6,168,464
REV	Actual Revenue (REV)3	$	12,338,247	23,353,111

The definitions for the commercial availability metrics are found in Appendix 2. These calculations were consolidated from a survey that Black & Veatch conducted across multiple plants concerning how they internally measure their availability while not ignoring the economics surrounding the sale of their power.

5.4 Comparing Model Outputs

The OUTPUTS section for the model also occurs on the "Scenarios" tab. The output reporting for the model is where a true analysis can be made. The output section allows for a fair evaluation of the differences between the plants being investigated. The plants are lined up side-by-side for comparison in table and chart format. As a new plant is loaded to the model, the outputs for the plant are added to the tables and charts as well.

5.4.1 Output Tables

The output tables generated by the calculator allow the user to easily review and compare the aspects of plants to highlight their differences and similarities. The differences become readily apparent when viewed in this manner. Appendix 2 displays a screenshot of the main output table illustrating how the model organizes its output tables so that each plant is organized into a column for comparison against other plant columns. The plant differences can easily be reviewed by scanning across columns. The definitions for these output calculations can be found in Appendix 2. This table contains and is organized into the following order:

Capacity

- Maximum Capacity Factor if economics are ignored
- Actual Capacity Factor

Revenue ($ then $/MWh)

Costs ($ then $/MWh)

- Fixed Operations & Maintenance Costs
- Variable Operations & Maintenance Costs
- Fuel Operations & Maintenance Costs

- Total Fuel and Variable Operations & Maintenance Costs
- Total Operations & Maintenance Costs

Profitability

Traditional Availability

- Equivalent Availability Factor (EAF)
- Equivalent Forced Outage Rate (EFOR)
- Equivalent Forced Outage Rate - Demand (EFORD)
- Forced Outage Factor (FOF)
- Forced Outage Rate (FOR)
- Planned Outage Factor (POF)

Capability

- Unit Capability Factor (UCF)
- Unplanned Capability Loss Factor (UCLF)

Commercial Availability

Period MWh Break Out

- Total Period Hours
- Period Megawatt Hours
- Generation Megawatt Hours
- Reserved Shutdown Megawatt Hours
- Planned Outage Megawatt Hours
- Forced Outage Megawatt Hours
- Maintenance Outage Megawatt Hours
- Derated Megawatt Hours
- Spinning Reserve Megawatt Hours
- Equivalent Forced Derated Megawatt Hours
- Equivalent Forced Derated Megawatt Hours During Reserve Shutdown

5.4.2 Output Trends

The PGP model generates several trends for quick comparison of the generated results. It uses bar, pie, and line charts to illustrate these differences by consolidating the all data for all plants at hand into graphs. Appendix E contains a sample collection of all output trends that the model generates. This section highlights a few of the trends to provide an example of the tools capabilities. The following list contains a list of some of the trends that the model generates to facilitate the comparison of the outputs:

Capacity Factor:
These trends illustrate the differing capacity across the plants

- Maximum Capacity Factor (based on demand curve only, ignoring economics)
- Actual Capacity Factor (considering economics and outage hours)

Period MWh Allocation:
These trends illustrate what state each plant is in over the period (i.e. Generating, Reserved Shutdown, Forced Outage, etc.)

- Generation MWh
- Reserved Shutdown MWh
- Planned Outage MWh
- Scheduled Outage MWh
- Maintenance Outage MWh
- Derated MWh
- Spinning Reserve MWh

Traditional Availability Metrics:
These trends illustrate how each plant performs from traditional availability standpoint.

- EFOR
- FOF
- FOR
- POF
- EAF
- UCLF
- UCF

Commercial Availability:
These trends illustrate how each plant performs from a commercial availability standpoint.

Revenue and Profitability:
These trends illustrate how each plant performs financially. This includes trends for both total dollars as well as dollars per MWh.

- Revenue ($)
- Fuel Costs ($)
- Fixed O&M costs ($) (salaries, etc.)
- Variable O&M Costs ($) (maintenance, etc.)

Typical Daily Generation-Revenue: there are a few additional charts that illustrate the typical behavior of the current plant, illustrating across a typical weekday and weekend day for each season, the state that the unit will be in (reserved shutdown/ generating/etc.) for each hour. It also illustrates the revenue generated during each hour for typical days for each season.

6. Conclusions

The PGP committee's Working Group 1 focus is to analyse the best ways to measure, evaluate, and apply power plant performance and availability data to promote plant performance improvements worldwide. From the aspect of this paper, it is not our goal to either support or challenge the hypothesis of whether markets, regulation, or technology are effective or not but, rather, focus on impacts on how the continued presence and importance of these drivers clearly alters:

- Goals/roles of the generator
- Applicable measures/means in which "performance" is evaluated and optimized by the generator.
- How commercial power producers, whether regulated or deregulated, feel the need to address performance for both existing and new generation assets.

During the last 3 years the global ESI has continued to evolve with vastly different structures being applied within different regions and equally wide impressions as to what degree change will continue, what form that change will take, and even, fundamentally, the success of regulatory and market restructuring.

It is interesting to note the parallels between the concept of commercial availability – where generation is essentially valued based on its ability to deliver when called upon – to evolving concepts for controlling emissions. Specifically, the implementation of cap and trade programs that limit overall emissions to the "cap" and require emitters to purchase allowance, in essence, transforms an environmental issue into a financial one.

Extensive work has been performed by PGP and other to evaluate how to be apply traditional technical performance indicators such as UCF, UPCLF, etc and emerging indicators for commercial availability. Unfortunately, fundamentally, there is no consistent, defined relationship between technical and commercial availability factors, greatly complicating the situation. This reality is rooted in the fact that commercial availability metrics are largely driven by when plants are "in the money." And are highly sensitive to both economic considerations (combination of market price and cost of production), as well as regional market characteristics (shape of load demand, technology stack, etc.).

To address this issue, Working Group 1 has developed a new computer-based tool to evaluate and compare technical and performance metrics. A series of case studies were developed presented within the context of the model to illustrate how to better apply and leverage both peer group data and as well the broader set of indicators. This model also fully documents and provides basis of calculations for all major current technical and performance indicators. Model examples can be used to demonstrate and test various market, technical performance, and economic assumptions.

Similarly, PGP's work must consider the increasingly complex measures of performance. Specifically, in addition to technical and commercial

"There is immense value in pursuing the objective of defining means to benchmark unit performance in terms of commercial issues."

performance, further analysis is warranted on the following:

- How should the industry measure performance in the future?
- Are there other performance measures or metrics to address such issues as sustainability?
- How will changes between developed and developing country priorities alter this picture?
- Are additional tools/techniques going to be required to "bridge" performance across different regions/situations?
- How with changes in generation mix or technologies impact needs for performance data collection, analysis, and benchmarking.

Further, growing concerns for CO_2 and greenhouse gas emission issues has raised the stakes for performance with expectations that shifting priorities will tend to:

- Place greater emphasis on performance of existing plant to include availability, capacity, efficiency, environmental, and cost management.
- Emphasis on plant modifications/technology deployment to limit emissions of existing plants; this trend is likely to be witnessed in developed countries in advance of developing countries.
- Emphasis on increasing "CO2 neutral" content of power portfolios will lead to the deployment of more renewables (and additional nuclear generation, in some regions).

Acceleration of implementation of power generation facilities employing "new" technologies including IGCC, CO2 capture and CO2 sequestration, among others.

Clearly, more work is required by the PGP to evaluate the validity/value or our model to help address these considerations. It is equally clear that, given the continued state of the ESI (different markets, different regulations, different technologies, etc.), there is immense value in pursuing the objective of defining means to benchmark unit performance in terms of commercial issues. This issue will be further evaluated in the next 3-year period of PGP activities.

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Appendix A
Calculation Definitions

This appendix contains a listing of all calculations used by the model. Each calculation listed has a text description and a formula.

Maximum Capacity Factor

This is the capacity factor that is calculated using the plant demand curve only. This ignores economic factors such as the price curve, and costs (fuel, fixed & variable O&M, etc.) It also does not factor in outages and derates.

$$MCF = \frac{\max MWh\ in\ operation\ using\ demand\ curve}{period\ MWh} \times 100 = \frac{MAXMWH}{PMWH} \times 100$$

Actual Capacity Factor

This is the capacity factor after factoring in economics (using price curve to calculate revenue, then comparing revenue to fuel & variable O&M costs to see if operation is profitable), and taking out the outages and derated MWh.

$$CF = \frac{econ\ MWh\ in\ service - MWh\ in\ outages / derates}{period\ MWh} \times 100$$
$$= \frac{ECMWH - POMWH - FOMWH - MOMWH - DRMWH}{PMWH} \times 100$$

Actual Revenue

This is the total revenue calculated using the economically dispatched revenue and considering outages and derates.

$$REV = \max econ rev - planned outage rev lost - forced outage rev lost - maint outage rev lost - derate rev los$$
$$= MAXREV - POREV - FOREV - MOREV - DRREV$$

Actual Margin

This is the total margin calculated using the economically dispatched revenue (considering outages and derates) minus the plant fuel, variable & fixed O&M costs.

Equivalent Availability Factor

The fraction of the maximum generation that could be provided if limited only by outages and deratings.

$$EAF = \frac{available\ generation}{\max imum\ generation} \times 100 = \frac{AG}{MG} \times 100 = \frac{AH - (EUNDH + ESDH)}{PH} \times 100$$

Equivalent Forced Outage Rate (EFOR)

$$EFOR = \frac{forced\ outage\ hours + sum\ of\ equivalent\ forced\ derated\ hours}{service\ hours + forced\ outage\ hours + sum\ of\ equivalent\ reserve\ shutdown\ forced\ derated\ hou}$$
$$= \frac{FOH + EFDH}{SH + FOH + ERSFDH} \times 100$$

Equivalent Forced Outage Rate (EFOR

$$EFORd = \frac{(FOHd + EFDHd)}{(SH + FOHd)} \times 100 = \frac{((FOH \times f) + (EFDH \times EFDHRS))}{(SH + (FOH \times f))} \times 100$$

$$= \frac{\left((FOH \times \left[\frac{\frac{1}{r} + \frac{1}{T}}{\frac{1}{r} + \frac{1}{T} + \frac{1}{D}}\right]\right) + (EFDH \times EFDHRS))}{(SH + (FOH \times \left[\frac{\frac{1}{r} + \frac{1}{T}}{\frac{1}{r} + \frac{1}{T} + \frac{1}{D}}\right]))} \times 100$$

Forced Outage Factor

Percentage of period hours in a forced outage.

$$FOF = \frac{forced\ outage\ hours}{period\ hours} \times 100 = \frac{FOH}{PH} \times 100$$

Forced Outage Rate

The ratio of the forced outage time to the generating service and forced outage time.

$$FOR = \frac{forced\ outage\ hours}{forced\ outage\ hours + service\ hours} \times 100 = \frac{FOH}{FOH + SH} \times 100$$

Planned Outage Factor

The percentage of the period that the unit is in planned outage.

$$POF = \frac{planned\ outage\ hours}{period\ hours} \times 100 = \frac{POH}{PH} \times 100$$

Commercial Availability – Definition 1

This measures the % of revenue that is affected by outages and derates. The higher it is, the less the revenue was affected by the outages and derates.

$$\mathrm{CA1} = \frac{\text{Actual Econ Rev \$ considering Derates/Outages}}{\text{Actual Econ Rev \$ w/o Outages/Derates}} \times 100 = \frac{A}{B} \times 100$$

Commercial Availability – Definition 2

This measures the same % of revenue that is affected by outages and derates as definition #1, but it only considers fuel prices when determining when to run. Variable O&M costs are not factored into decisions to operate or not. The higher the percentage, the less the hours in the money were impacted by outages and derates. "hours in the money" is defined as when fuel costs are lower than market price for this definition.

$$\mathrm{CA2} = \frac{\text{Actual Hours in the Money, after Outages/Derates}}{\text{Hours in the \$, based on fuel price only}} \times 100 = \frac{A}{B} \times 100$$

Commercial Availability – Definition 3

This calculates the "Balance Account", which is the dollar figure sum when comparing the hourly difference remaining between the actual profit versus the profit expected using an availability factor. better the actual profit was than the expected profit using an availability factor. The higher the number, the better the actual profit was than the expected profit using an availability factor.

$$\mathrm{CA3} = \sum \mathrm{Hourly} \begin{bmatrix} \text{Generation Considering Outages/Derates - (Economic Dispatched Generation} \times \text{Availability Factor)} \times \\ \text{(LMP} - \text{NonFixed Fuel and O \& M Costs)} \end{bmatrix}$$

Commercial Availability – Definition 4

This measures the percentage difference between the margins using the outage/derate hours and not. This calculation also ignores fixed costs. The higher the percentage, the more impact that outages/derates had on margin.

$$\text{CA4} = \frac{\text{Actual Margin Ignoring Fixed Costs}}{\text{Actual Margin Ignoring Fixed Costs \& Outages \& Derates}} \times 100 = \frac{A}{B} \times 100$$

Commercial Availability – Definition 5

This measures the percentage of margin affected by outages and derates, much like definition #1, but ignoring fixed costs. The higher the percentage, the less the plant's margin was affected by outages and derates.

$$\text{CA5} = \frac{\text{Actual Margin Ignoring Fixed Costs}}{\text{Actual Margin Ignoring Fixed Costs \& Outages \& Derates}} \times 100 = \frac{A}{B} \times 100$$

Commercial Availability – Definition 6

This measures the % of revenue affected by outages and derates exactly like definition #5, but only considering HOURS 7-24 for each day. The higher the %, the less the plant's revenue was affected by outages and derates.

$$\text{CA6} = \frac{\text{Actual Econ Rev}}{\text{Maximum Econ Rev}} \times 100 = \frac{A}{B} \times 100$$

Commercial Availability – Definition 7

This measures the percentage of margin affected by non-planned outages and derates, much like definition #6, but ignoring fixed costs & planned outages. The higher the percentage, the less the plant's margin was affected by forced/maintenance outages and derates.

$$\text{CA7} = \frac{\text{Actual Margin Ignoring Fixed Costs}}{\text{Actual Margin Ignoring Fixed Costs \& Outages \& Derates}} \times 100 = \frac{A}{B} \times 100$$

Commercial Unavailability – Definition 8

This definition is called "Commercial Unavailability" and measures the percentage of hours in outage/derated during total hours in the money. The higher the percentage, the more the plant was unavailable during profitable hours.

$$\text{CU} = \frac{\text{Actual Total MWh Lost to Outages/Derates}}{\text{Maximum Econ MWh}} \times 100 = \frac{A}{B} \times 100$$

Unit Capability Factor

Ratio of the available energy generation over a given time period to the reference energy generation over the same period of time, expressed as a percentage.

$$UCF = \frac{(REG - PEL - UEL) \times 100}{REG}$$

Unplanned Capability Loss Factor

Ratio of the unplanned energy losses during a given period of time, to the reference energy generation, expressed as a percentage.

$$UCLF = \frac{UEL \times 100}{REG}$$

Appendix B
Case Study Details

Study 1: 800 MW Pulverized Coal Across Market Loads

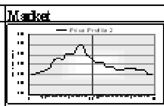
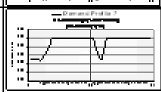
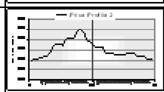
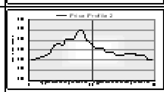
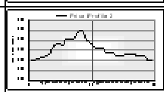
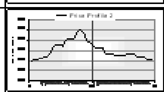
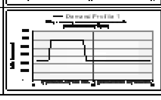
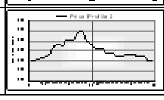
STUDY 1	MW	Technology	Demand	Market	$/MWh
Plant 1 800MW Pulverized Coal, Baseload Plant, in a Regulated Market	800	Pulverized Coal			Winter: $ 60 Spring/Fall: $ 50 Summer: $ 70
Plant 2 800MW Pulverized Coal, Baseload w/ Nightly Load Following, in a Regulated Market	800	Pulverized Coal			Winter: $ 60 Spring/Fall: $ 50 Summer: $ 70
Plant 3 800MW Pulverized Coal, Daily Full Load, Min Load Night and Weekend, in a Regulated Market	800	Pulverized Coal			Winter: $ 60 Spring/Fall: $ 50 Summer: $ 70
Plant 4 800MW Pulverized Coal, Baseload Plant, in a Non-Regulated Market	800	Pulverized Coal			Winter: $ 80 Spring/Fall: $ 100 Summer: $ 120
Plant 5 800MW Pulverized Coal, Baseload w/ Nightly Load Following, in a Non-Regulated Market	800	Pulverized Coal			Winter: $ 80 Spring/Fall: $ 100 Summer: $ 120
Plant 6 800MW Pulverized Coal, Daily Full Load, Min Load Night and Weekend, in a Non-Regulated Market	800	Pulverized Coal			Winter: $ 80 Spring/Fall: $ 100 Summer: $ 120

Figure B-1.1
Study 1 Plants Being Investigated

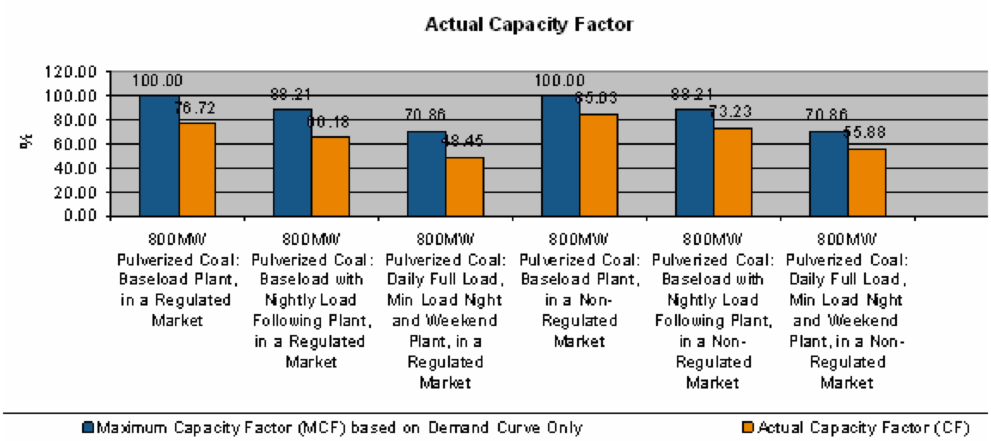


Figure B-1.2
Actual Capacity Factor

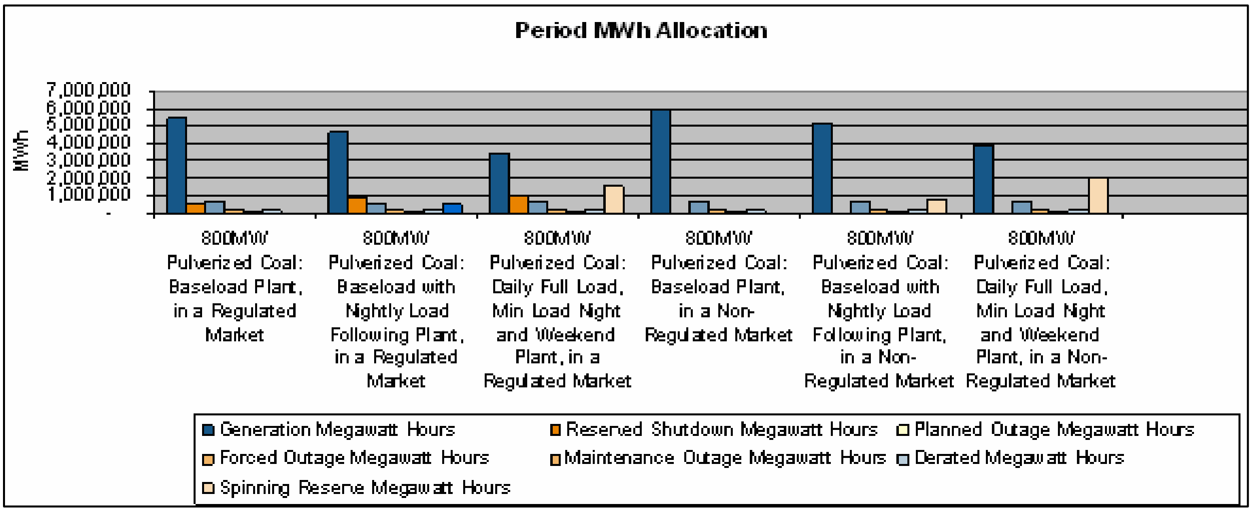


Figure B-1.3
Period MWh Allocation

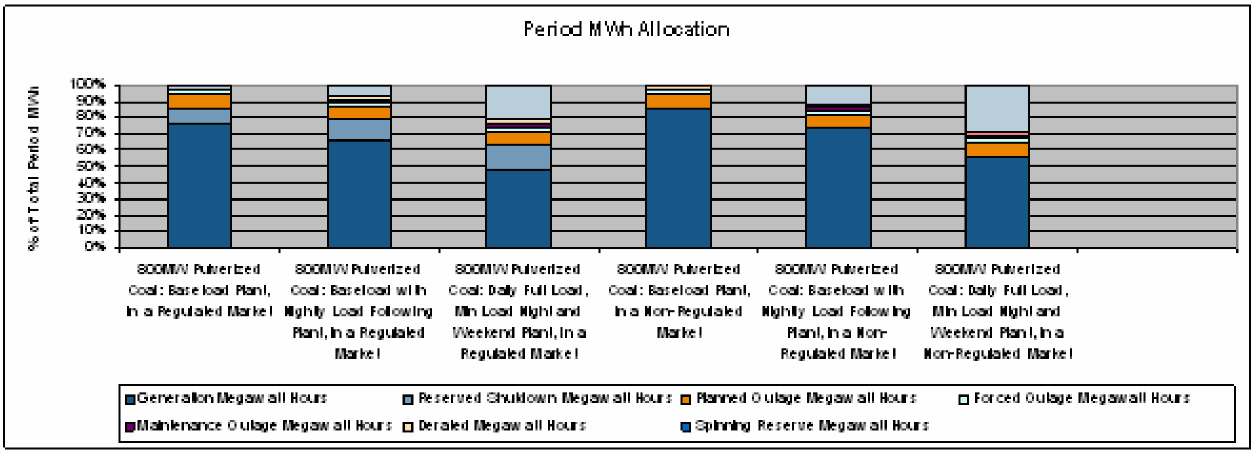


Figure B-1.4
Period MWh Allocation

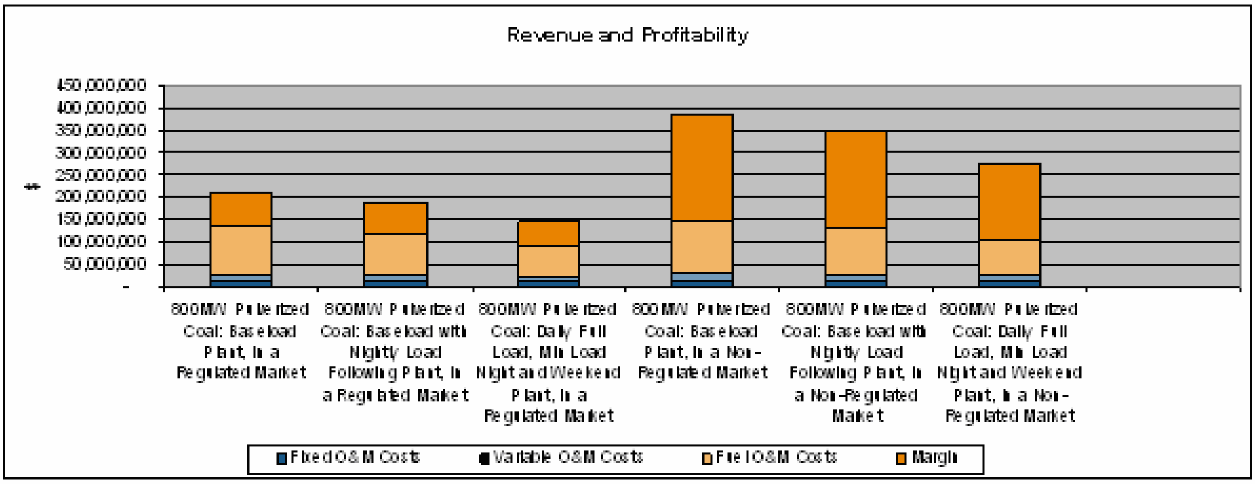


Figure B-1.5
Revenue and Profitability

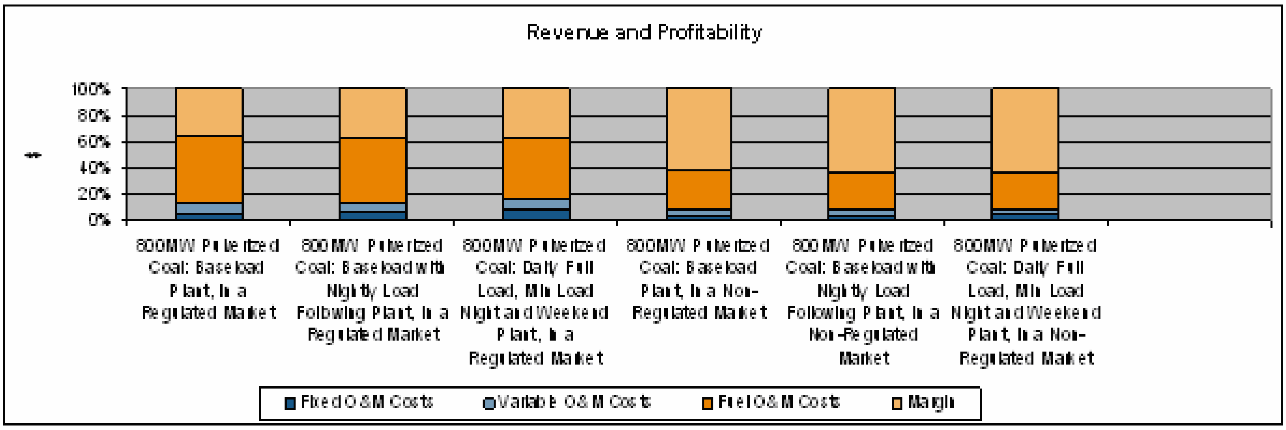


Figure B-1.6
Revenue and Profitability

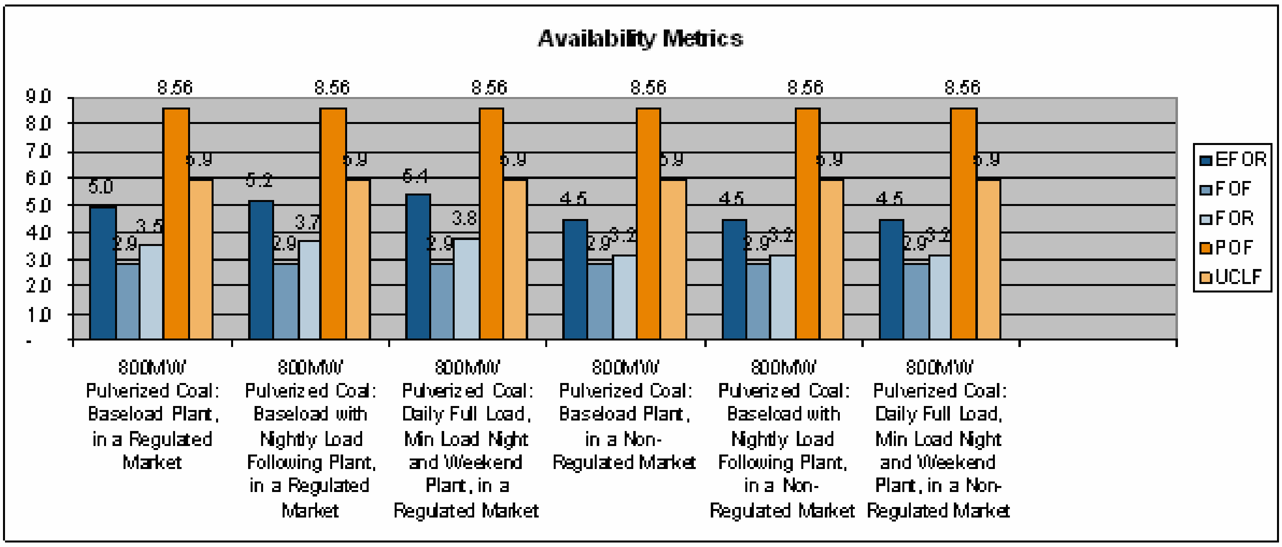


Figure B-1.7
Availability Metrics

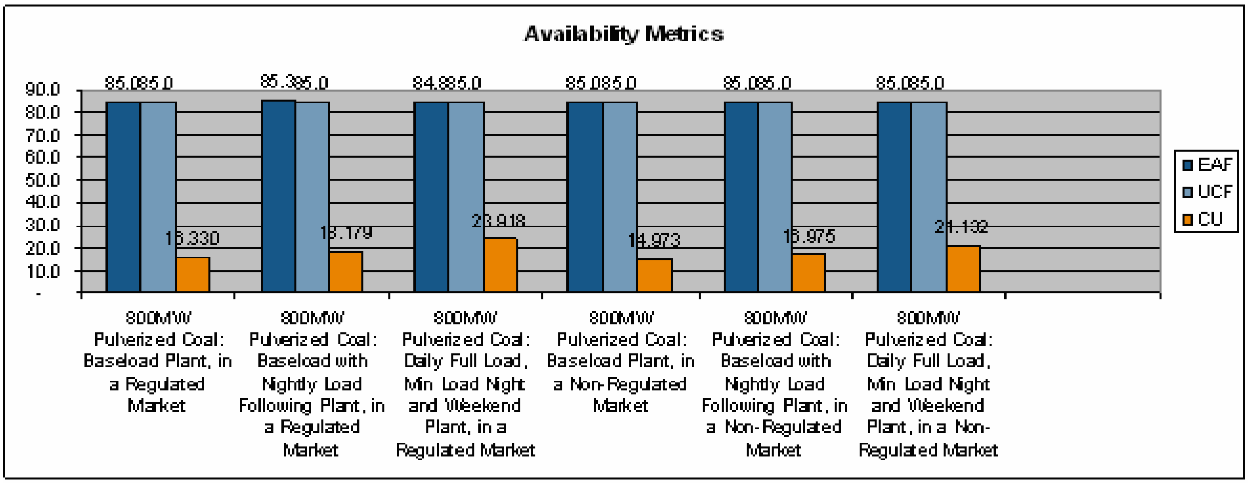


Figure B-1.8
Availability Metrics

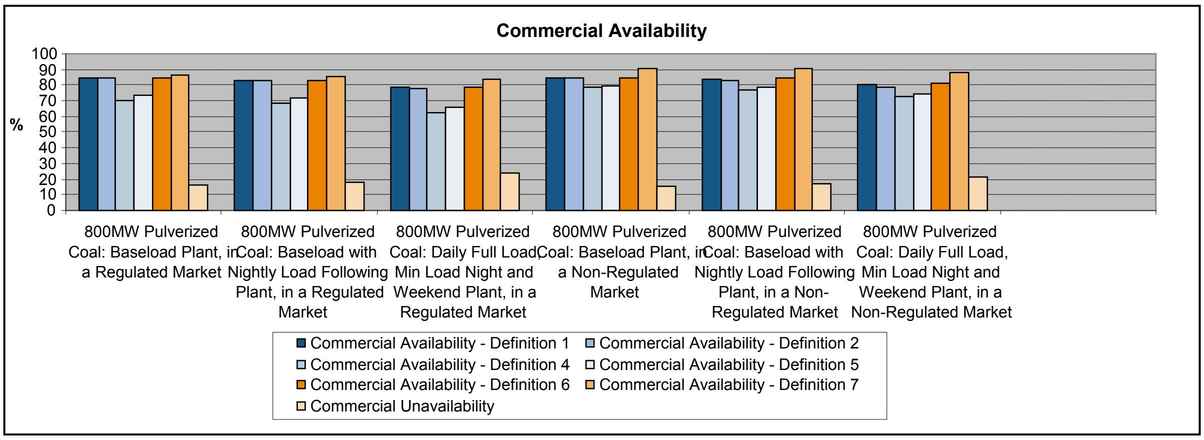


Figure B-1.9
Commercial Availability

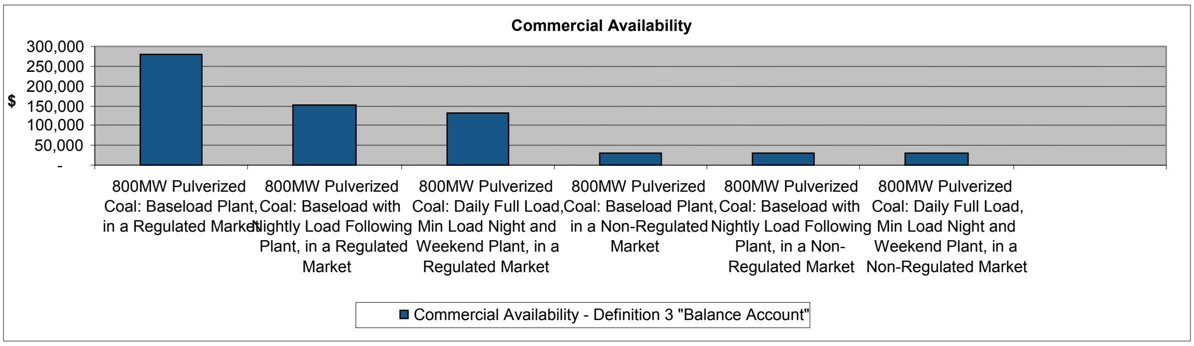


Figure B-1.10
Commercial Availability

Study 2: 300 MW Oil-Fired Steam Plants in Varying Markets

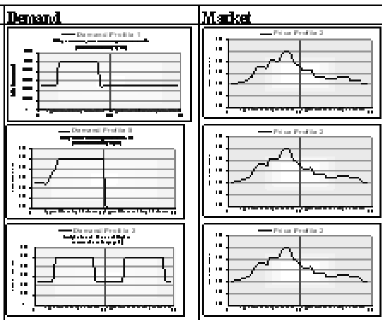
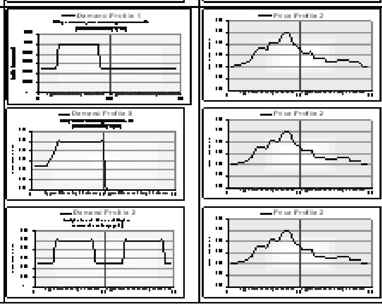
STUDY 2	MW	Technology	Demand	Market	$/MWh
Plant 1 300MW Oil-Fired Steam, Varying Seasonal Dispatch Plant, in a Regulated Market	300	Oil-Fired Steam Winter			Winter: $ 60
		Spring/Fall			Spring/Fall: $ 50
		Summer			Summer: $ 70
Plant 2 300MW Oil-Fired Steam, Varying Seasonal Dispatch Plant, in a Deregulated Market	300	Oil-Fired Steam Winter			Winter: $ 60
		Spring/Fall			Spring/Fall: $ 100
		Summer			Summer: $ 120

Figure B-2.1
Study 2 Plants Being Investigated

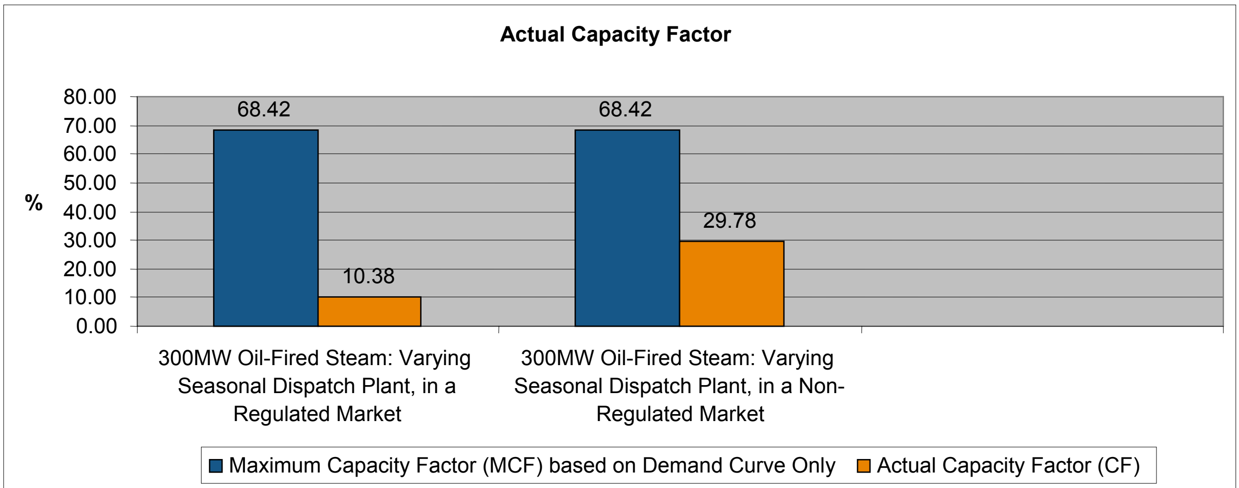


Figure B-2.2
Actual Capacity Factor

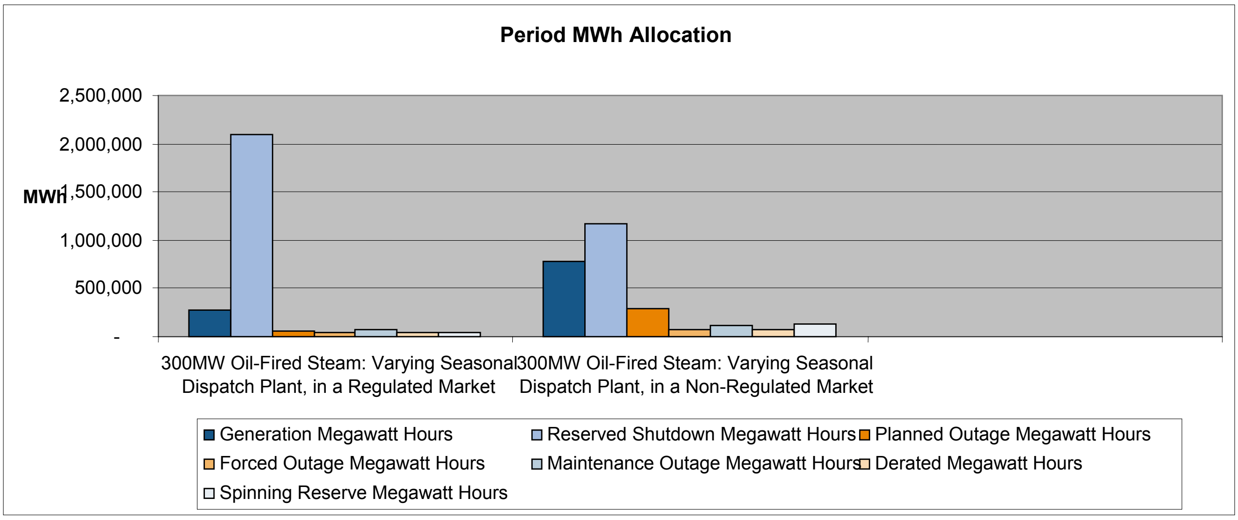


Figure B-2.3
Period MWh Allocation

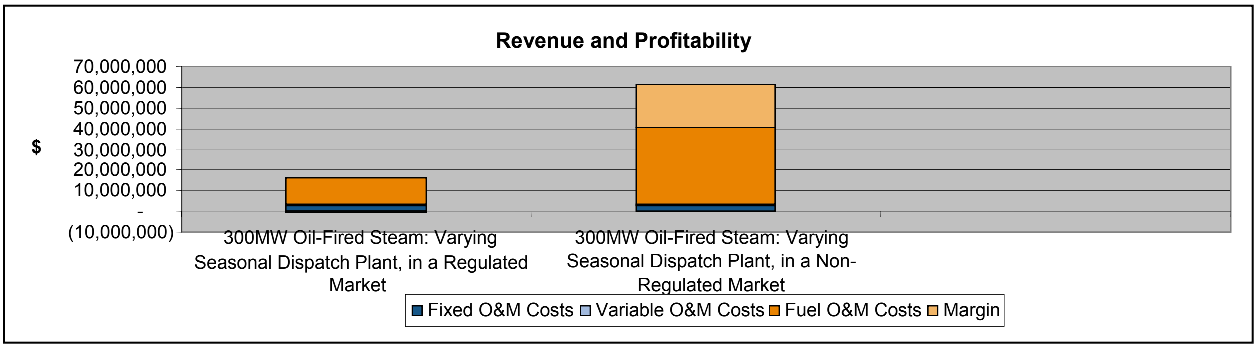


Figure B-2.4
Revenue and Profitability

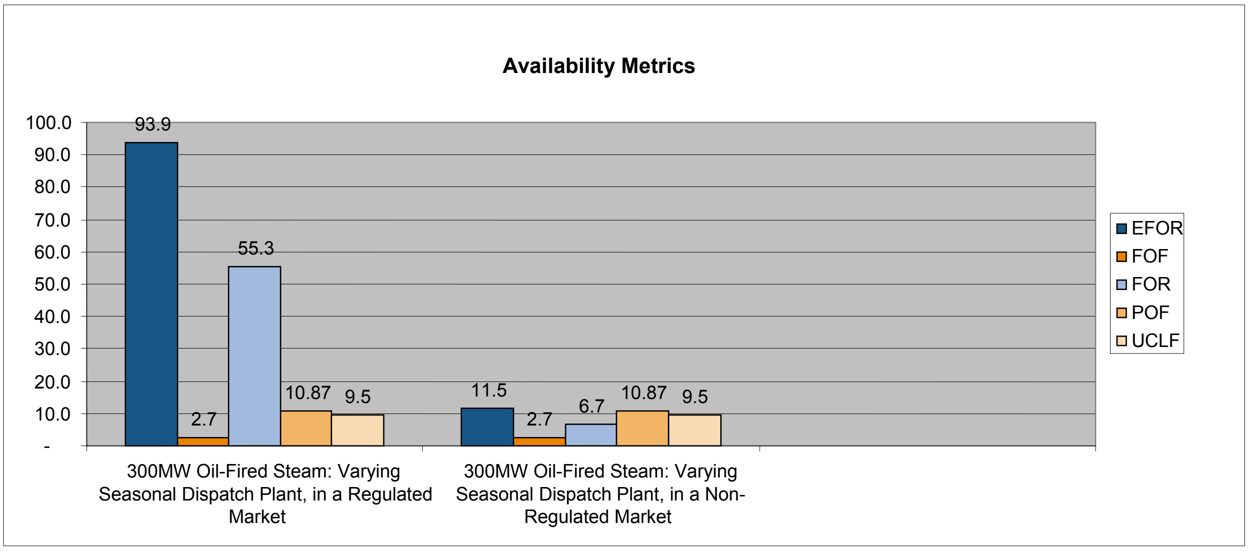


Figure B-2.5
Availability Metrics

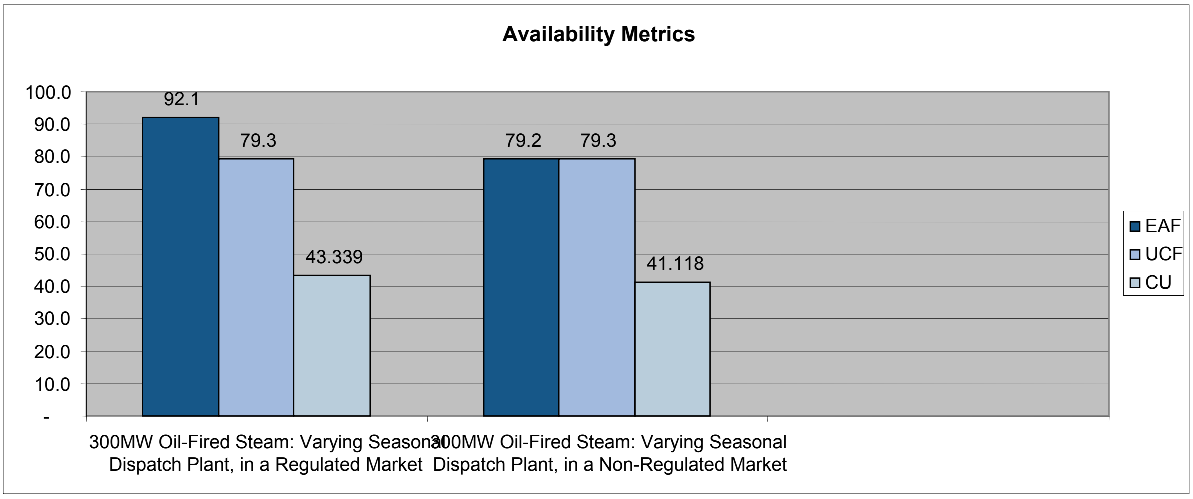


Figure B-2.6
Availability Metrics

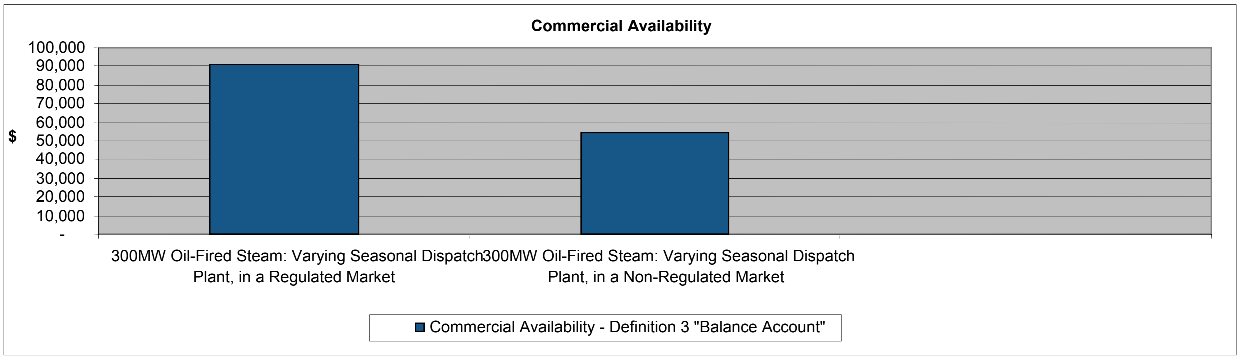
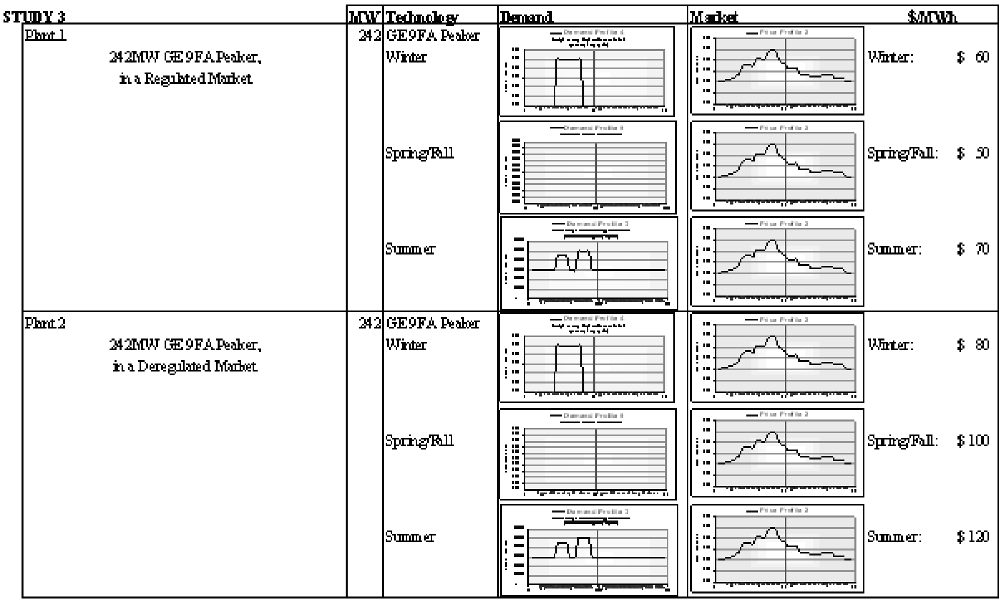


Figure B-2.7
Commercial Availability

Study 3: 242 MW Peaker in Varying Markets



STUDY 3	MW	Technology	Demand	Market	$/MWh
Plant 1 242MW GE 9FA Peaker, in a Regulated Market	242	GE9FA Peaker Winter			Winter: $ 60
		Spring/Fall			Spring/Fall: $ 50
		Summer			Summer: $ 70
Plant 2 242MW GE 9FA Peaker, in a Deregulated Market	242	GE9FA Peaker Winter			Winter: $ 80
		Spring/Fall			Spring/Fall: $ 100
		Summer			Summer: $ 120

Figure B-3.1
Study 3 Plants Being Investigated

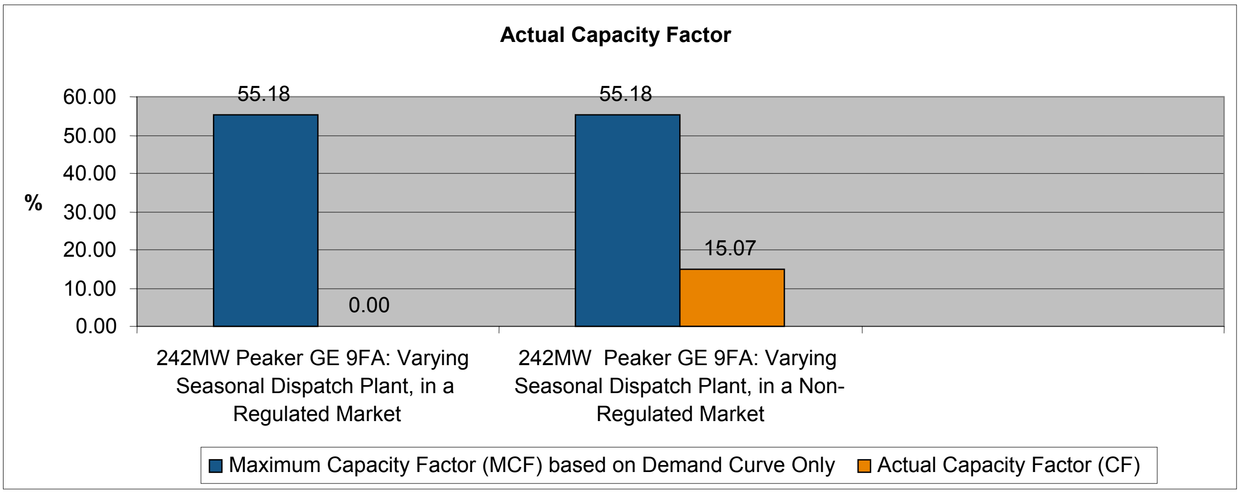


Figure B-3.2
Actual Capacity Factor

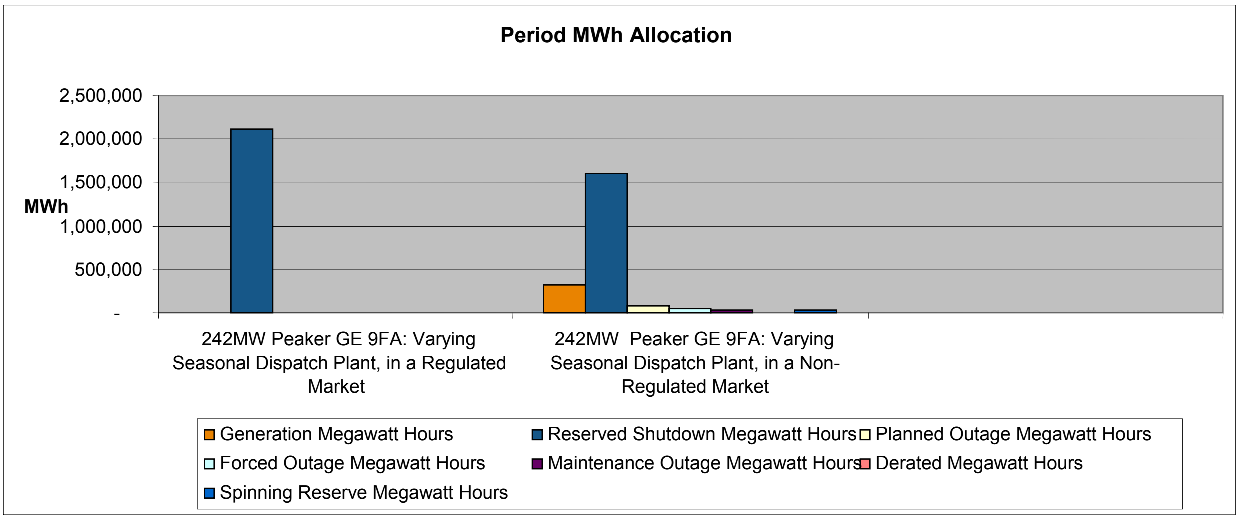


Figure B-3.3
Period MWh Allocation

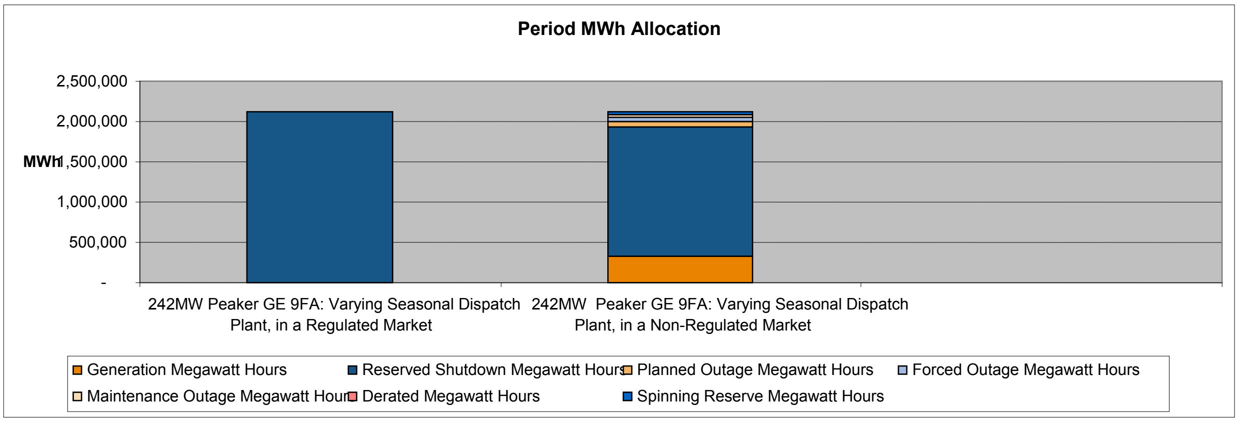


Figure B-3.4
Period MWh Allocation

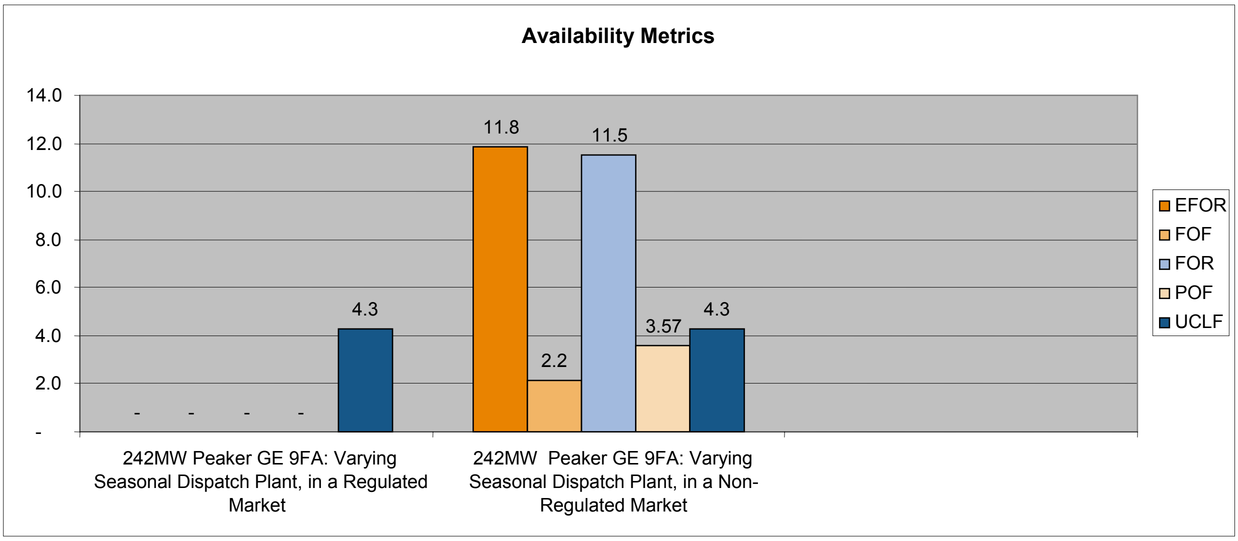


Figure B-3.5
Availability Metrics

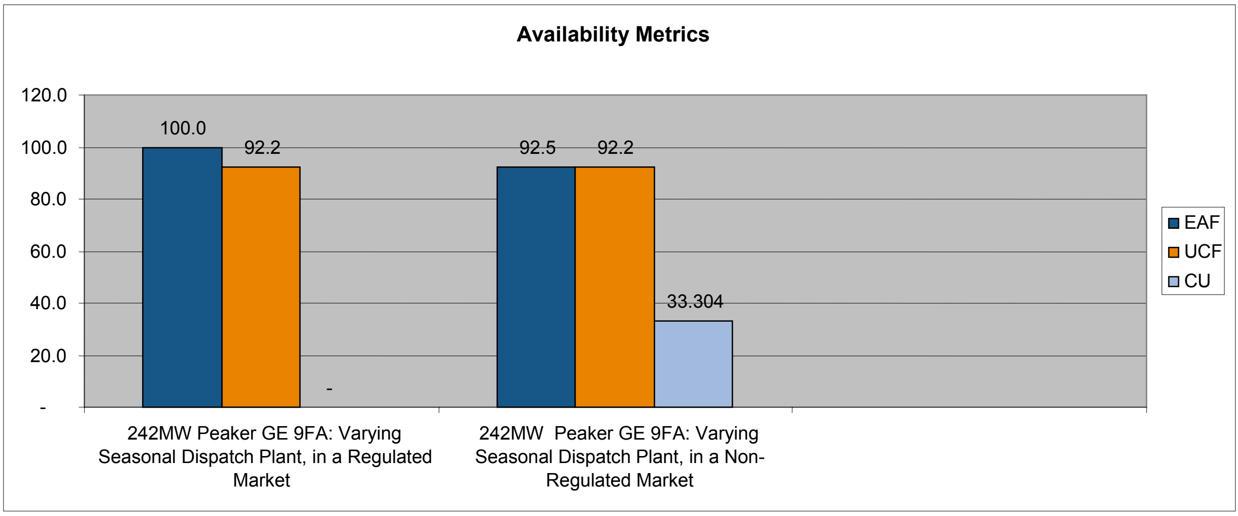


Figure B-3.6
Availability Metrics

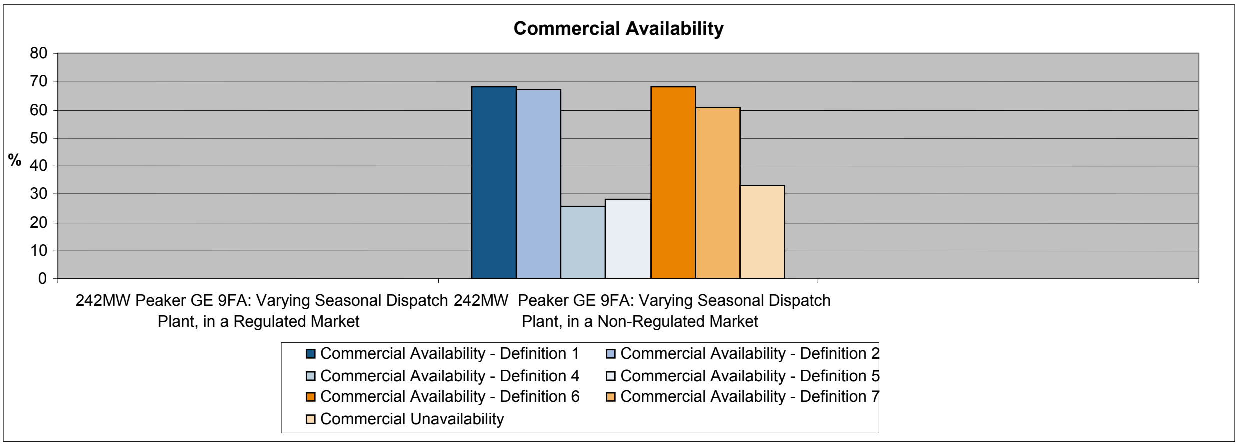


Figure B-3.7
Commercial Availability

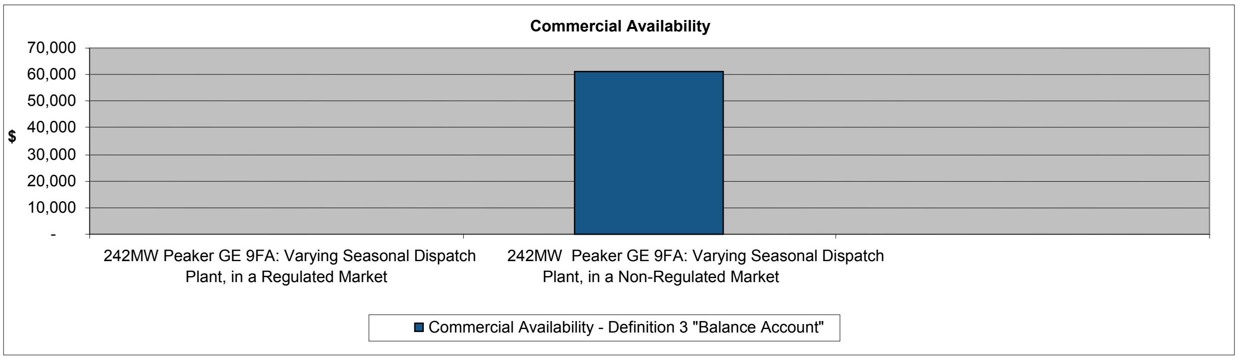


Figure B-3.8
Commercial Availability

Study 4: 75 MW Pulverized Coal Across Various Markets

STUDY 4	MW	Technology	Demand	Market	$/MWh
Plant 1 75MW Pulverized Coal, Various Demand Curves, in a Regulated Market	75	Pulverized Coal Winter			Winter: $ 60
		Spring/Fall			Spring/Fall: $ 50
		Summer			Summer: $ 70
Plant 2 75MW Pulverized Coal, Various Demand Curves, in a Deregulated Market	75	Pulverized Coal Winter			Winter: $ 60
		Spring/Fall			Spring/Fall: $ 100
		Summer			Summer: $ 120

Figure B-4.1
Study 4 Plants Being Investigated

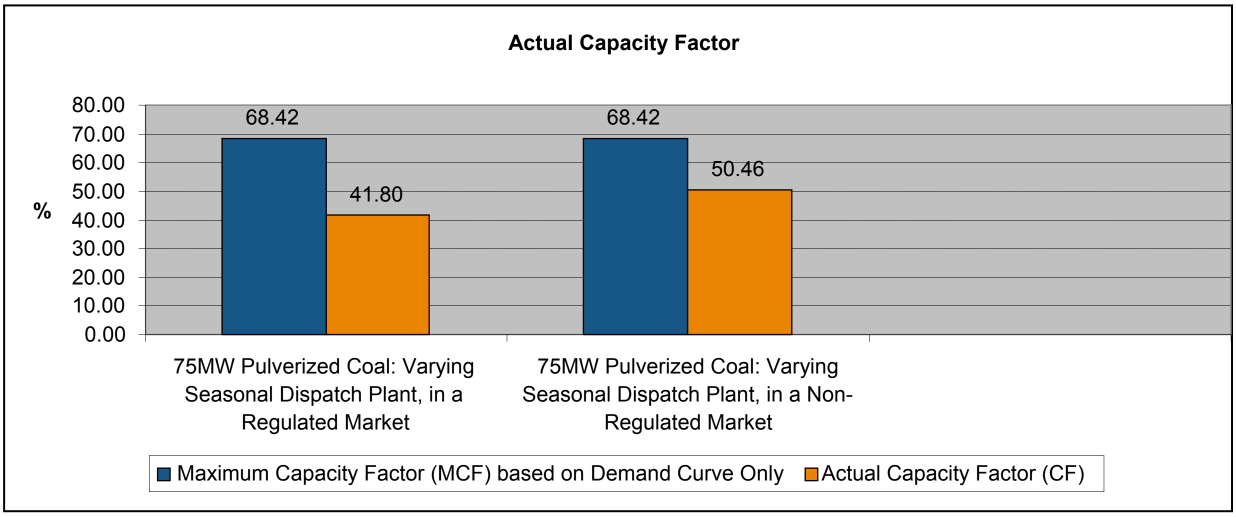


Figure B-4.1
Actual Capacity Factor

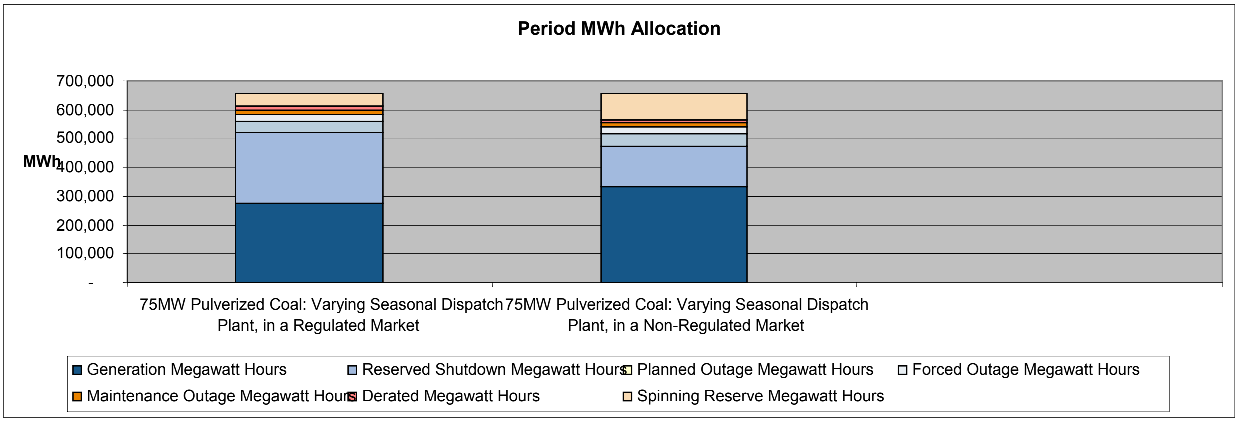


Figure B-4.2
Period MWh Allocation

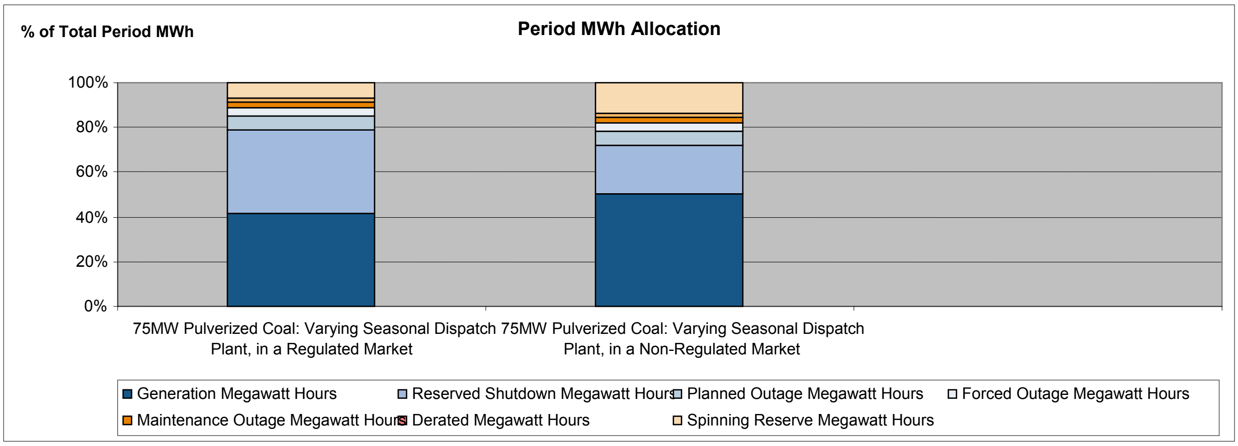


Figure B-4.3
Period MWh Allocation

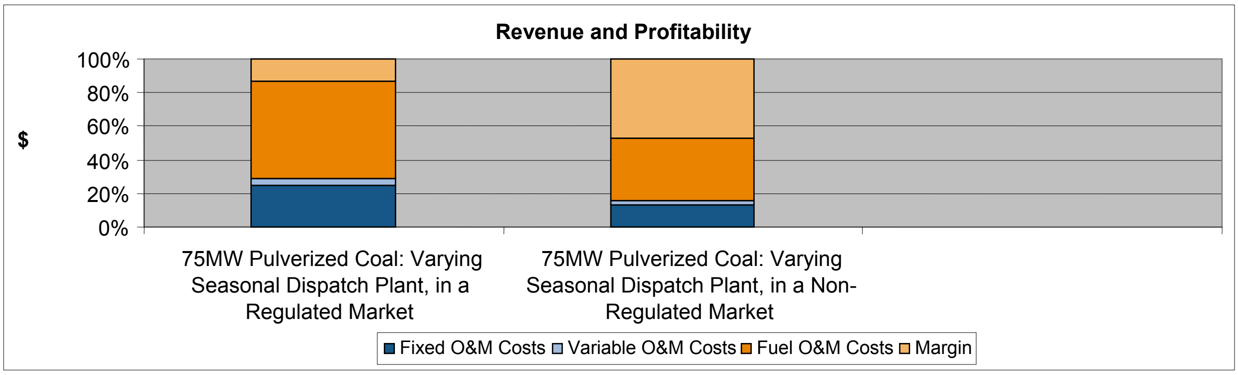
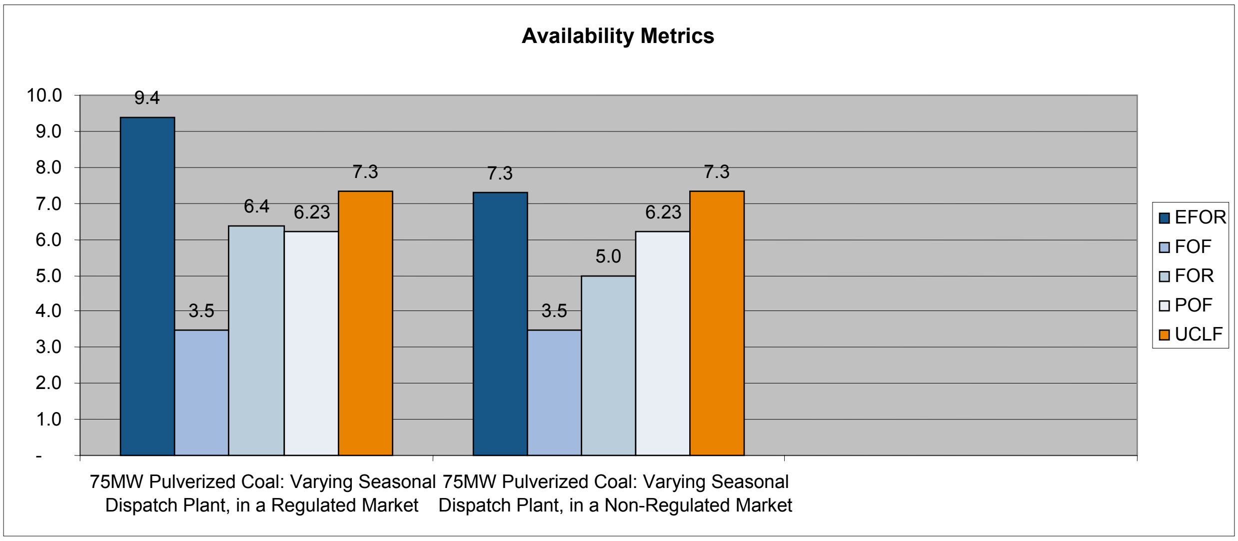


Figure B-4.4
Revenue and Profitability



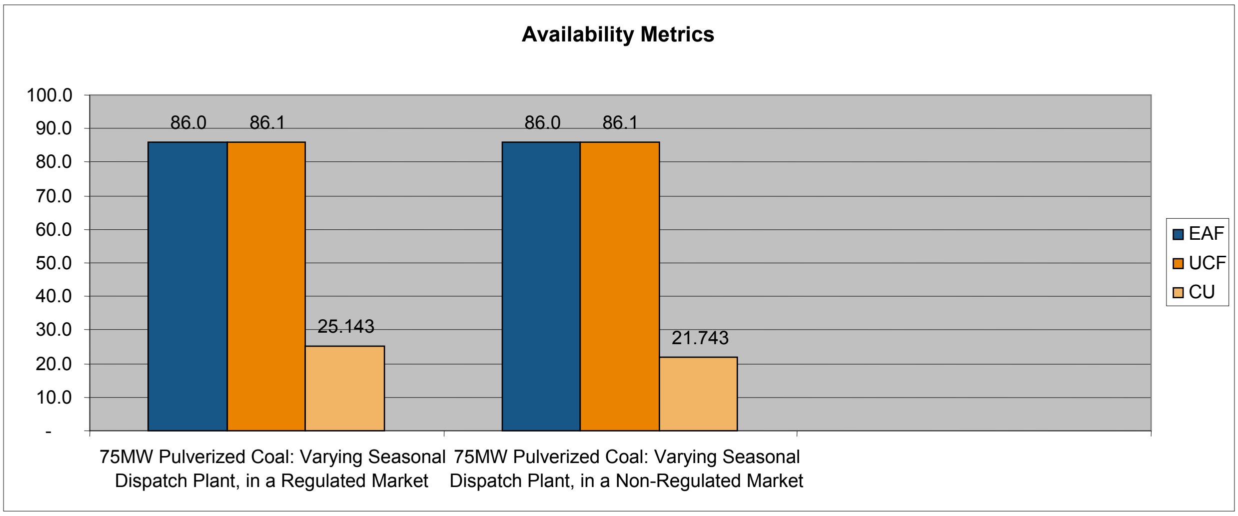


Figure B-4.6
Availability Metrics

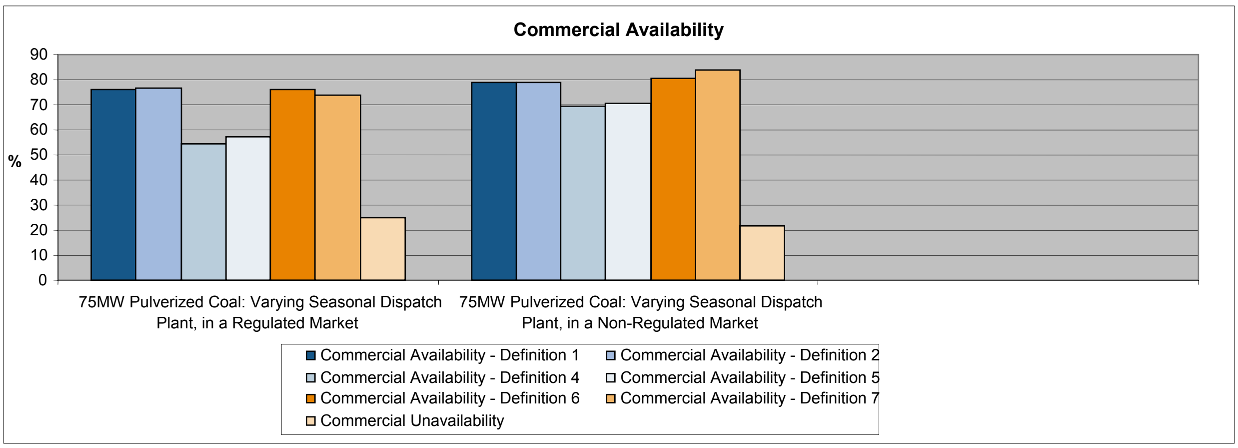


Figure B-4.7
Commercial Availability

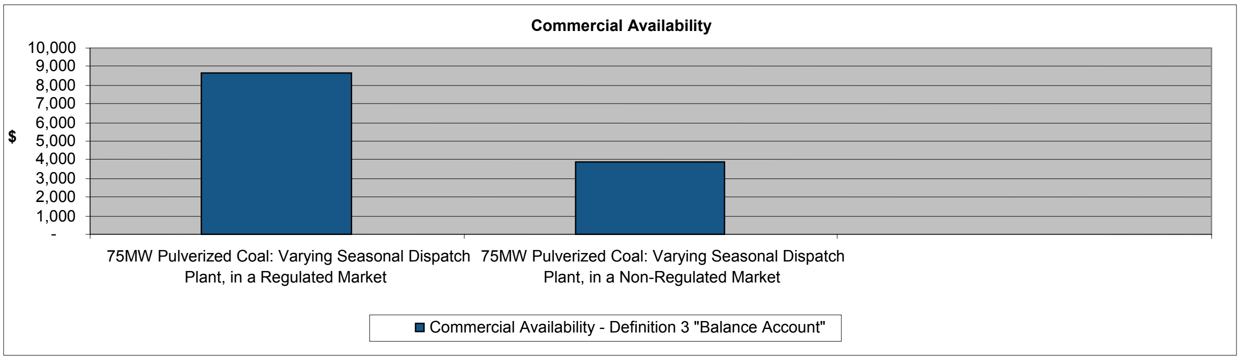
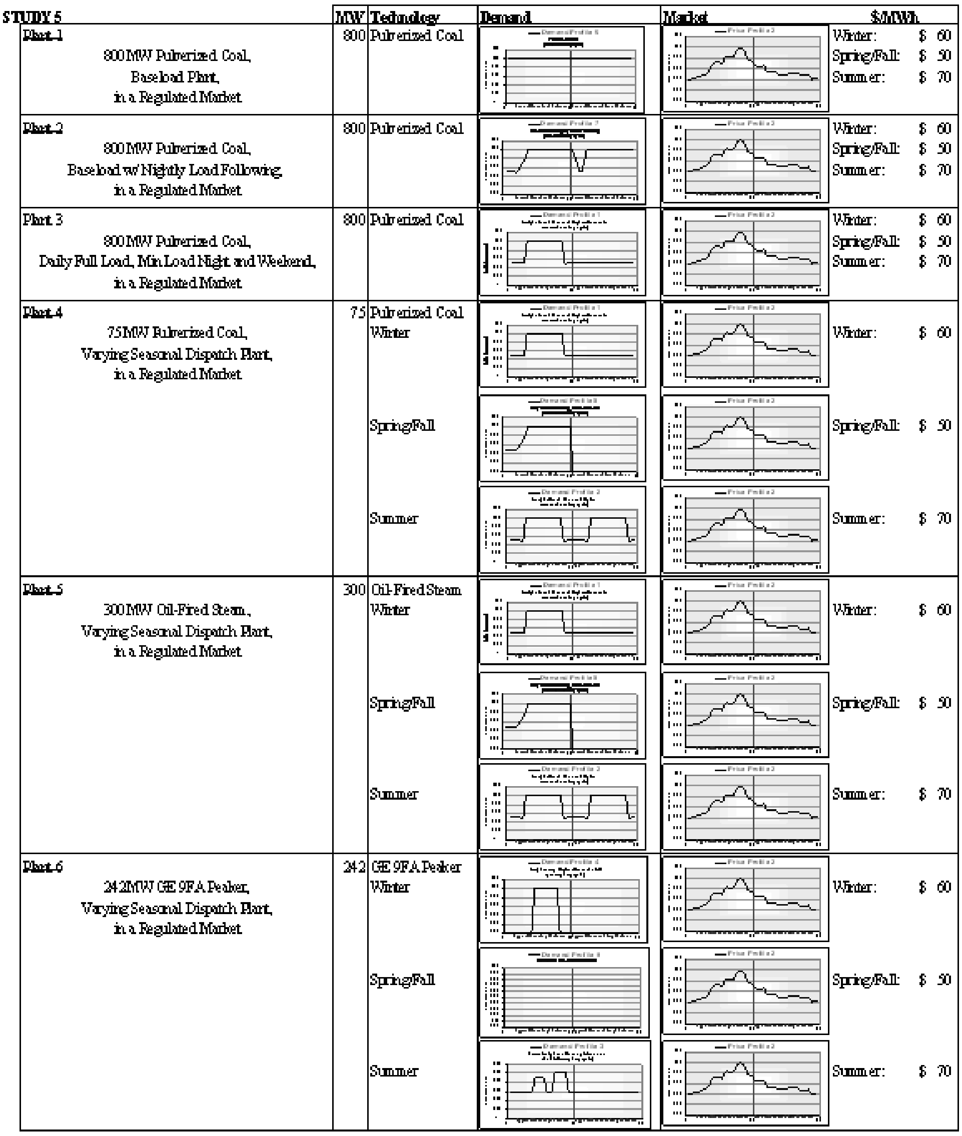


Figure B-4.8
Commercial Availability

Study 5: Pulverized Coal, Oil-Fired, Peaker in Regulated Market



STUDY 5	MW	Technology	Demand	Market	$/MWh
Plant 1 800MW Pulverized Coal, Baseload Plant, in a Regulated Market	800	Pulverized Coal			Winter: $ 60 Spring/Fall: $ 50 Summer: $ 70
Plant 2 800MW Pulverized Coal, Baseload w/ Nightly Load Following, in a Regulated Market	800	Pulverized Coal			Winter: $ 60 Spring/Fall: $ 50 Summer: $ 70
Plant 3 800MW Pulverized Coal, Daily Full Load, Min Load Night and Weekend, in a Regulated Market	800	Pulverized Coal			Winter: $ 60 Spring/Fall: $ 50 Summer: $ 70
Plant 4 75MW Pulverized Coal, Varying Seasonal Dispatch Plant, in a Regulated Market	75	Pulverized Coal Winter			Winter: $ 60
		Spring/Fall			Spring/Fall: $ 50
		Summer			Summer: $ 70
Plant 5 300MW Oil-Fired Steam, Varying Seasonal Dispatch Plant, in a Regulated Market	300	Oil-Fired Steam Winter			Winter: $ 60
		Spring/Fall			Spring/Fall: $ 50
		Summer			Summer: $ 70
Plant 6 242MW GE 9FA Peaker, Varying Seasonal Dispatch Plant, in a Regulated Market	242	GE 9FA Peaker Winter			Winter: $ 60
		Spring/Fall			Spring/Fall: $ 50
		Summer			Summer: $ 70

Figure B-5.1
Study 5 Plants Being Investigated

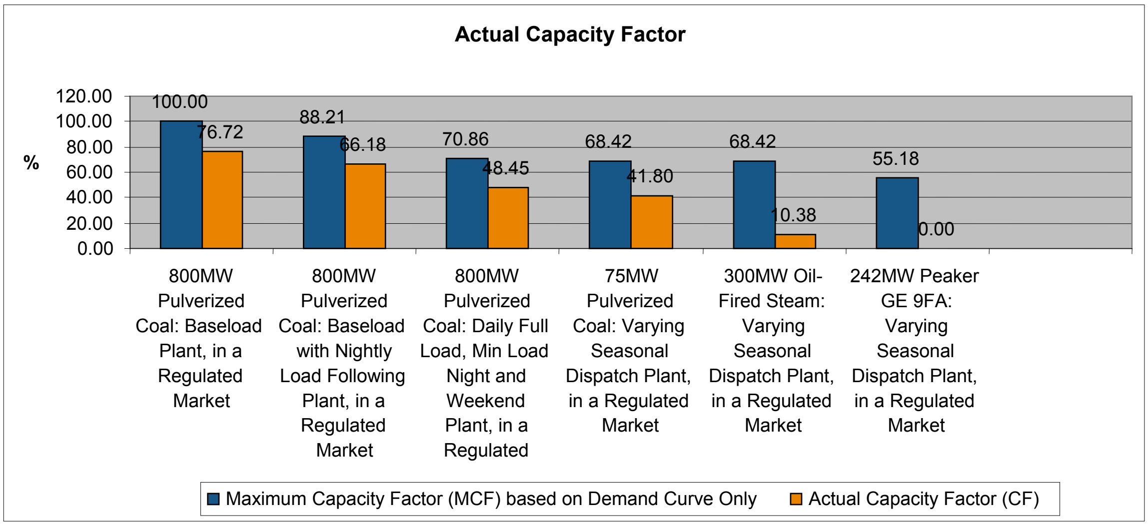


Figure B-5.2
Actual Capacity Factor

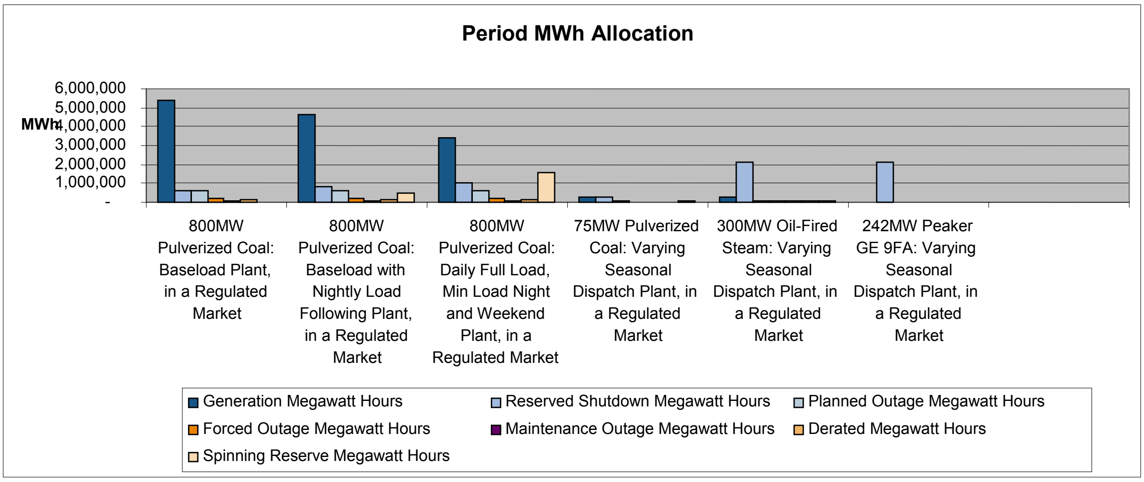


Figure B-5.3
Period MWh Allocation

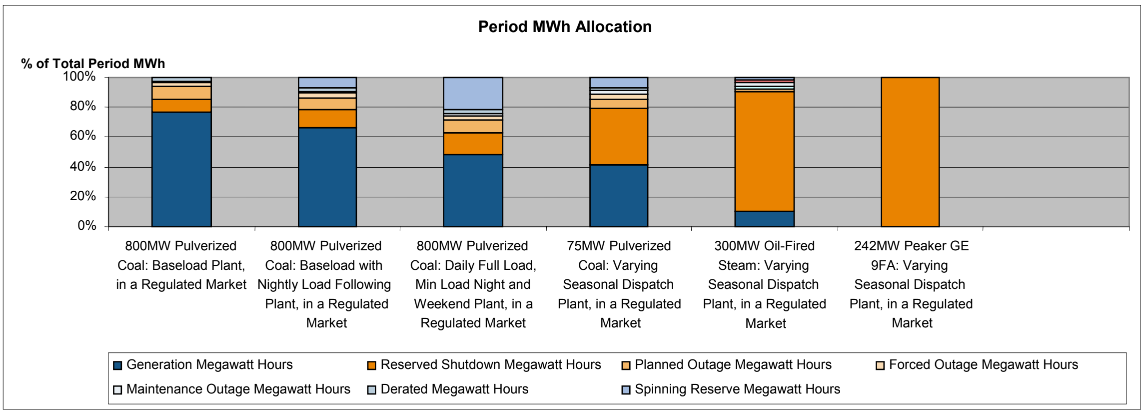


Figure B-5.4
Period MWh Allocation

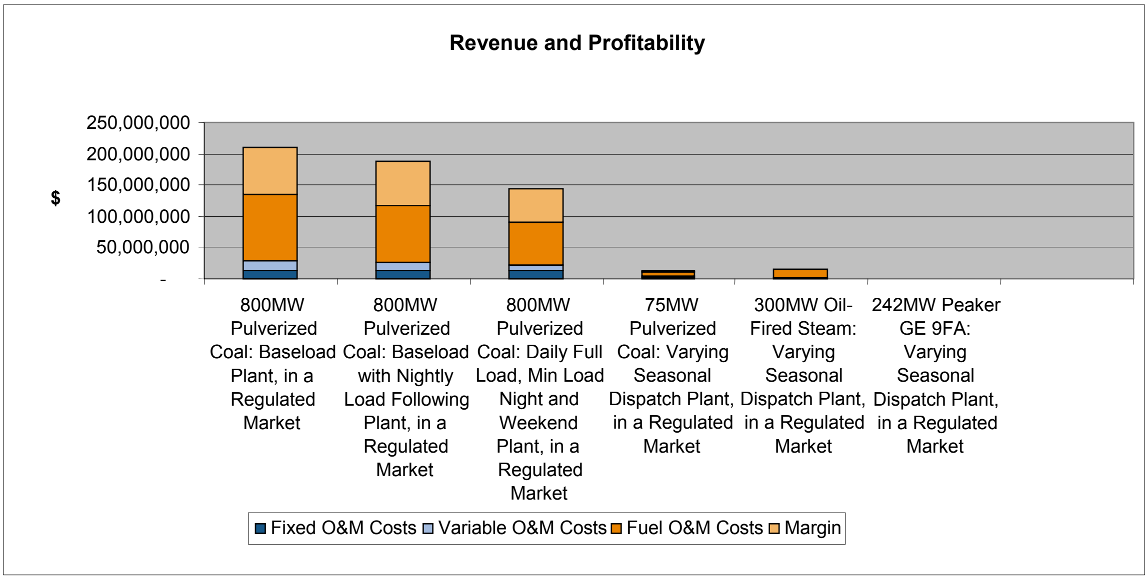


Figure B-5.5
Revenue and Profitability

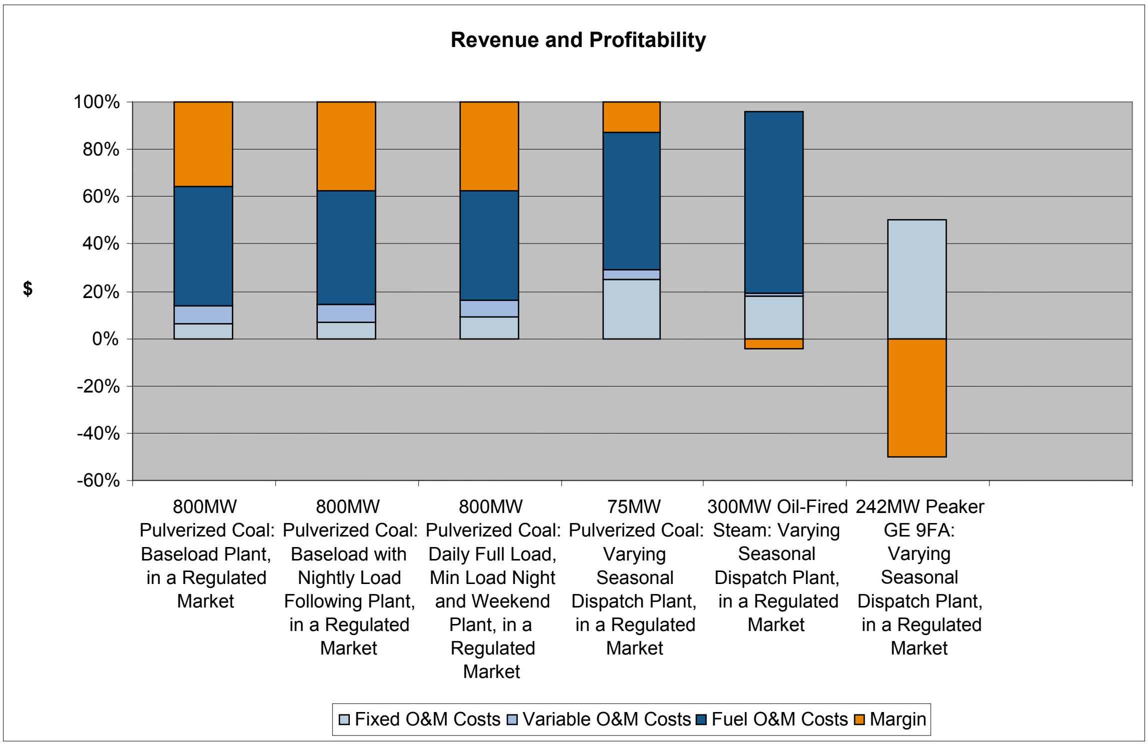


Figure B-5.6
Revenue and Profitability

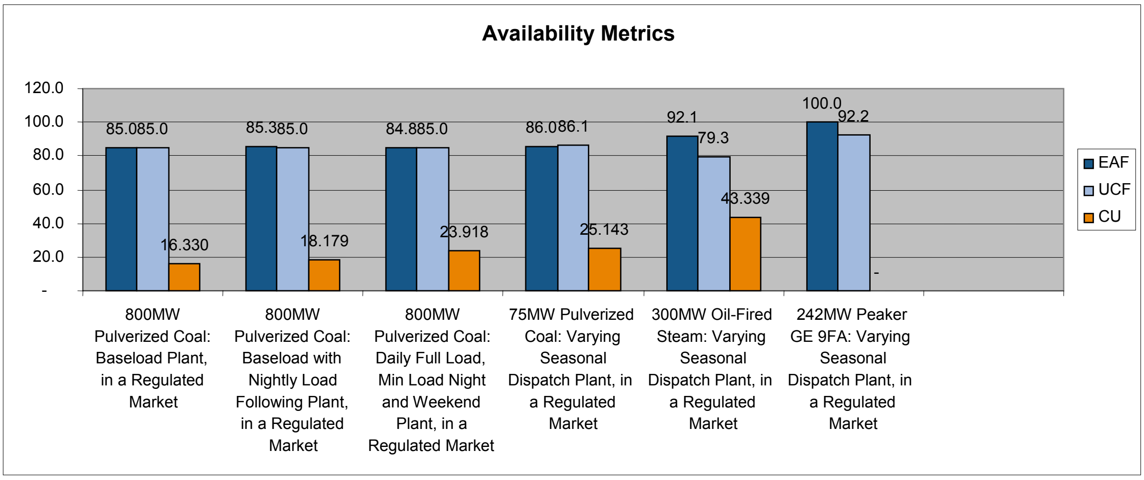


Figure B-5.7
Availability Metrics

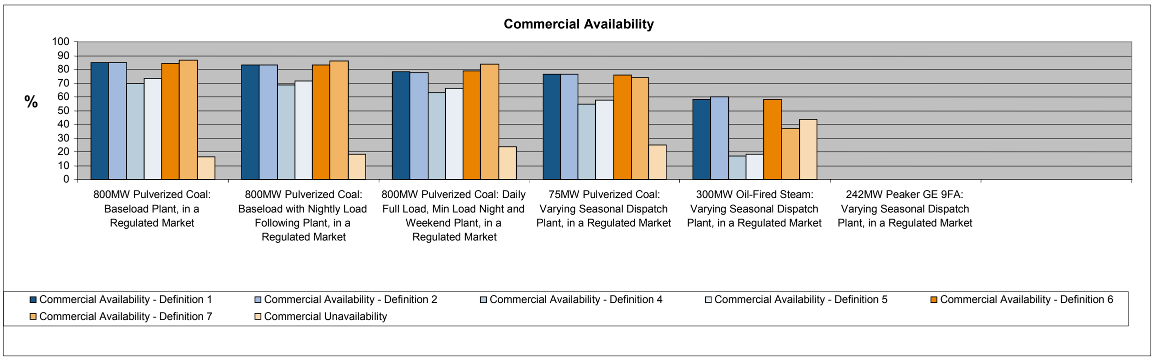
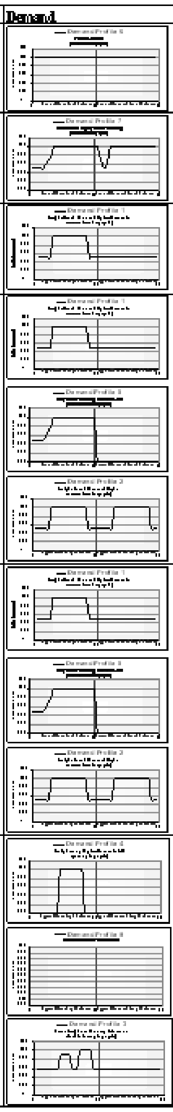


Figure B-5.8
Commercial Availability

Study 6: Pulverized Coal, Oil-Fired, Peaker in Regulated Market

STUDY 6	MW	Technology	Demand	Market	$/MWh
Plant 1 800MW Pulverized Coal, Baseload Plant, in a Deregulated Market	800	Pulverized Coal			Winter: $ 80 Spring/Fall: $ 100 Summer: $ 120
Plant 2 800MW Pulverized Coal, Baseload w/ Nightly Load Following, in a Deregulated Market	800	Pulverized Coal			Winter: $ 80 Spring/Fall: $ 100 Summer: $ 120
Plant 3 800MW Pulverized Coal, Daily Full Load, Min Load Night and Weekend, in a Deregulated Market	800	Pulverized Coal			Winter: $ 80 Spring/Fall: $ 100 Summer: $ 120
Plant 4 75MW Pulverized Coal, Varying Seasonal Dispatch Plant, in a Deregulated Market	75	Pulverized Coal Winter			Winter: $ 60
		Spring/Fall			Spring/Fall: $ 100
		Summer			Summer: $ 120
Plant 5 300MW Oil-Fired Steam, Varying Seasonal Dispatch Plant, in a Deregulated Market	300	Oil-Fired Steam Winter			Winter: $ 60
		Spring/Fall			Spring/Fall: $ 100
		Summer			Summer: $ 120
Plant 6 242MW GE 9FA Peaker, Varying Seasonal Dispatch Plant, in a Deregulated Market	242	GE 9FA Peaker Winter			Winter: $ 80
		Spring/Fall			Spring/Fall: $ 100
		Summer			Summer: $ 120



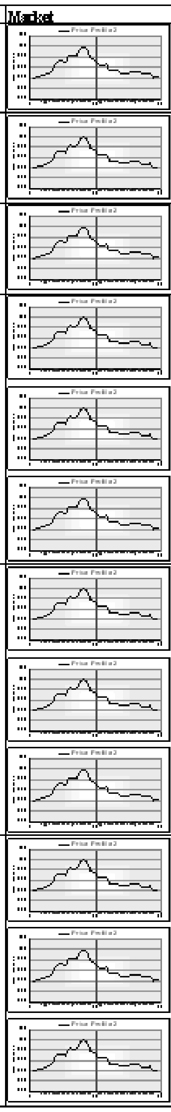


Figure B-6.1
Study 6 Plants Being Investigated

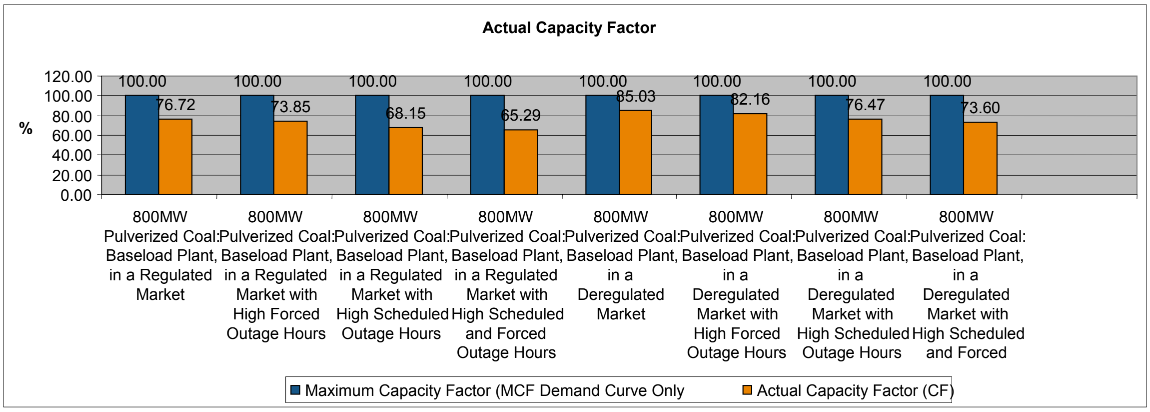


Figure B-6.2
Actual Capacity Factor

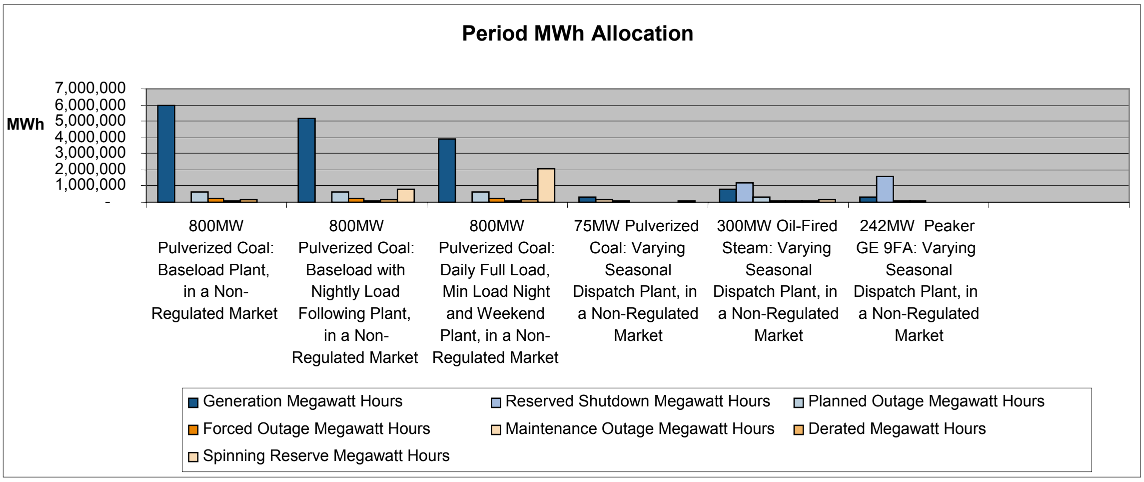


Figure B-6.3
Period MWh Allocation

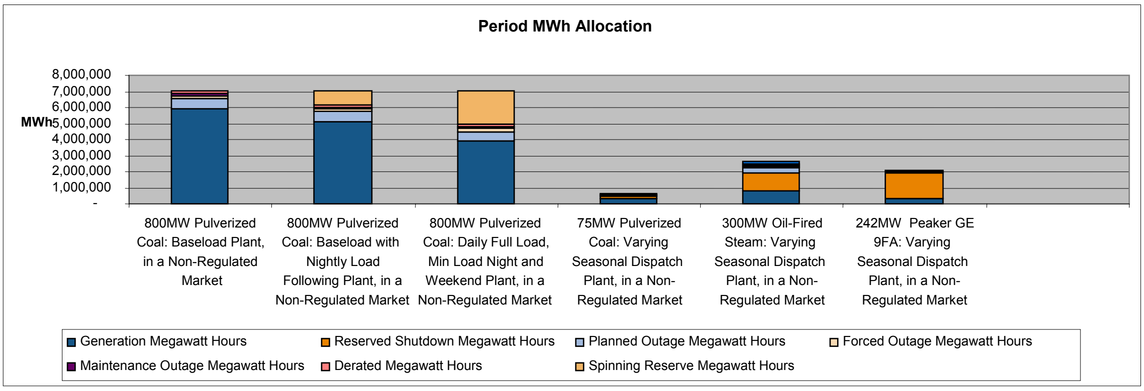


Figure B-6.4
Period MWh Allocation

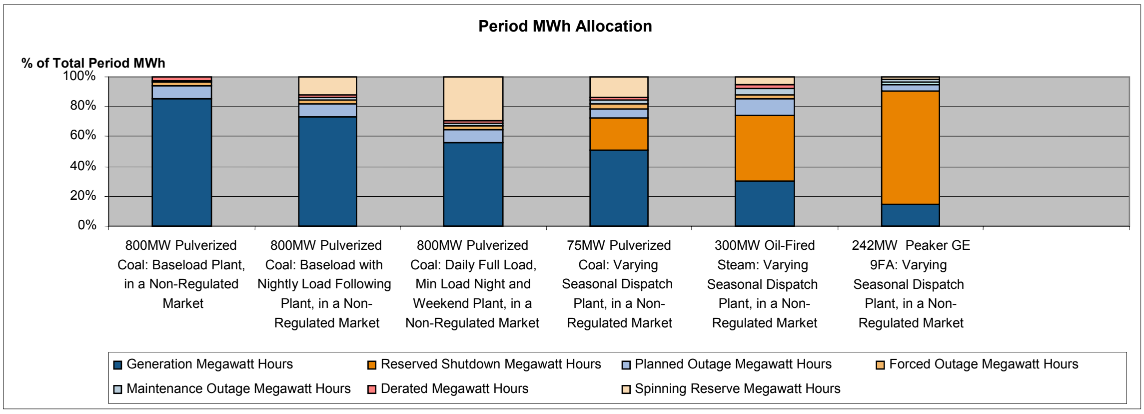


Figure B-6.5
Period MWh Allocation

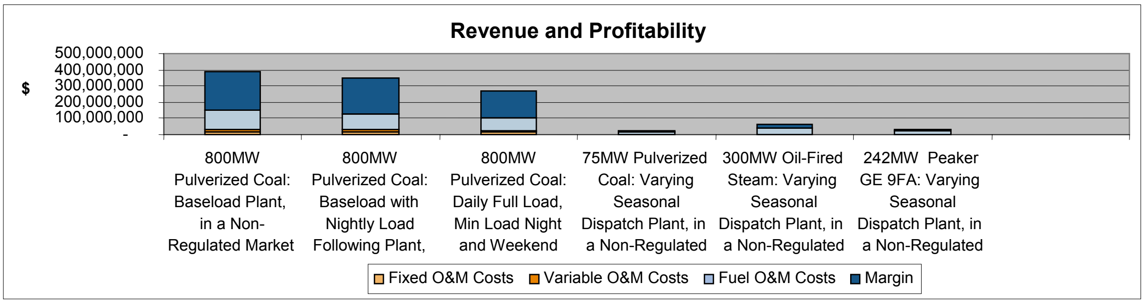


Figure B-6.6
Revenue and Profitability

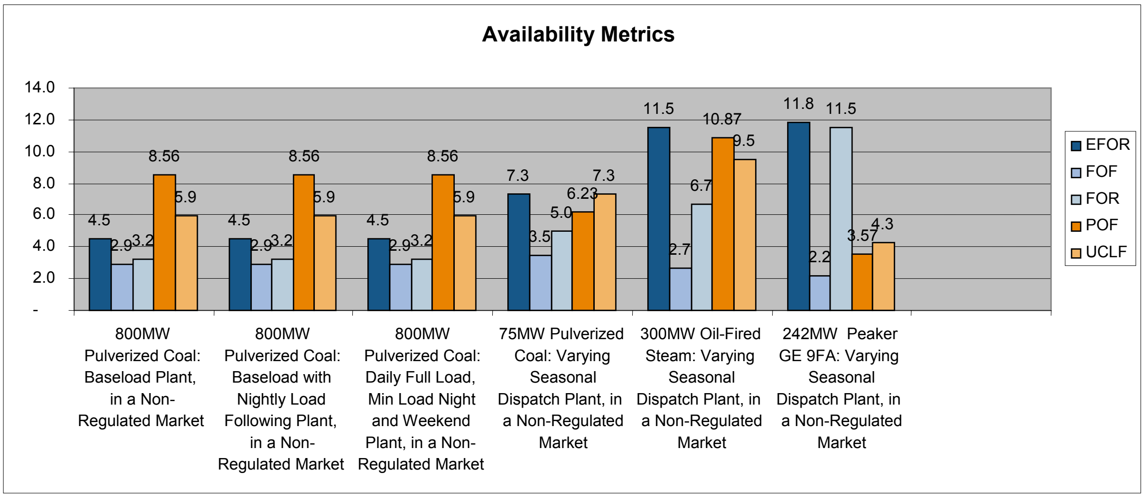


Figure B-6.7
Availability Metrics

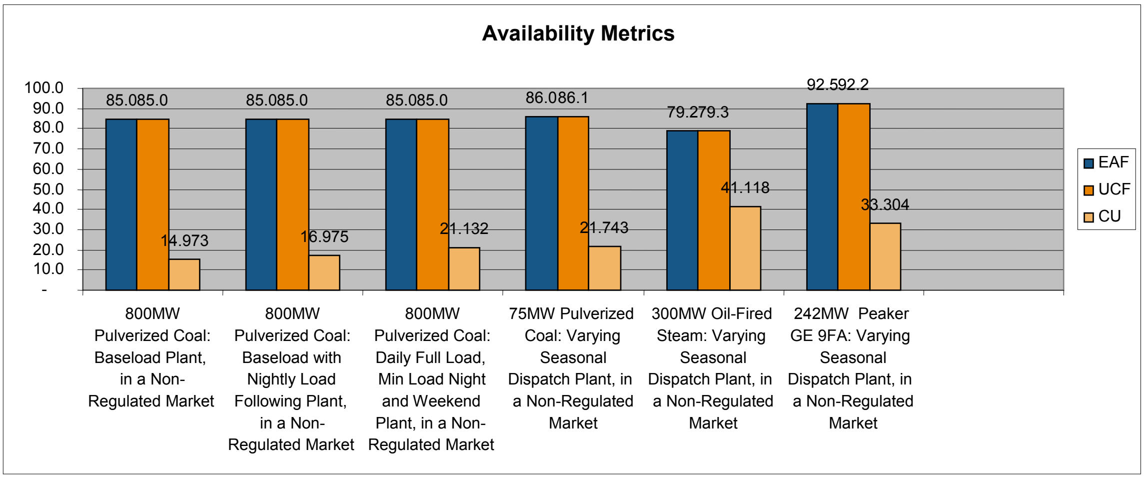


Figure B-6.8
Availability Metrics

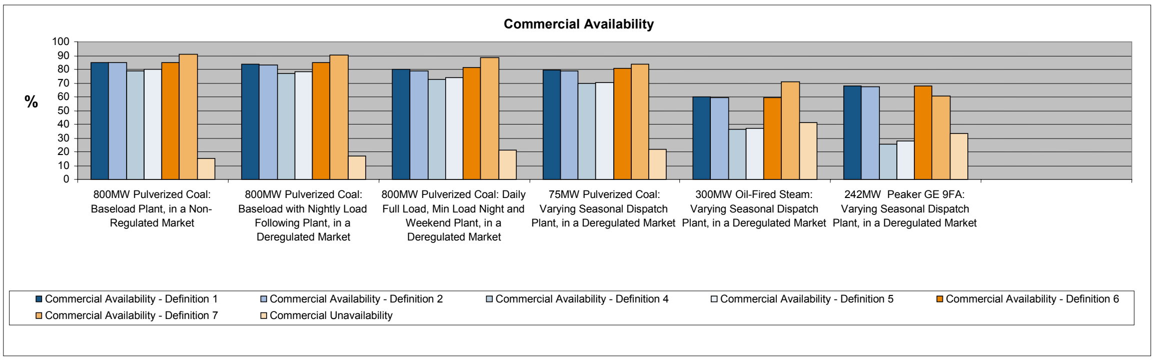


Figure B-6.9
Commercial Availability

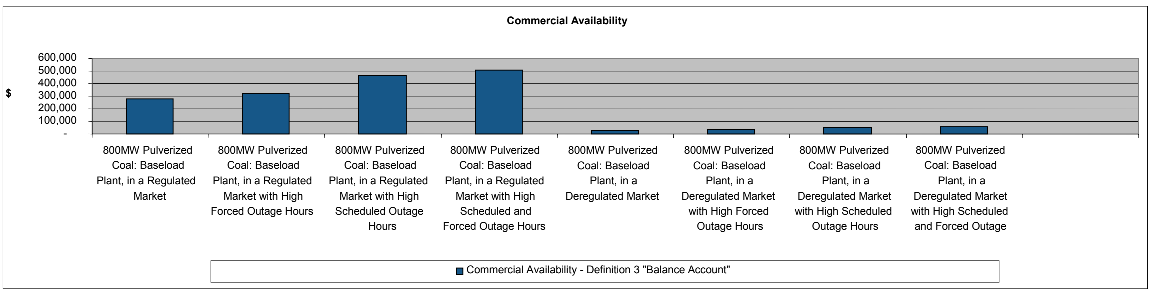


Figure B-6.10
Commercial Availability

Study 7: Pulverized Coal with Forced/Scheduled Outages

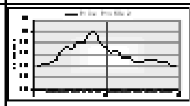
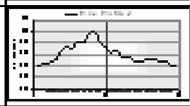
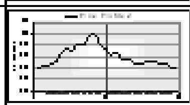
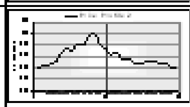
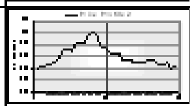
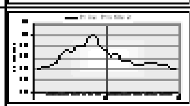
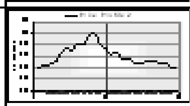
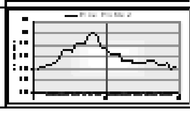
STUDY 7	MW	Technology	Demand	Market	$/MWh	Planned Outage Hours	Forced Outage Hours
Plant 1 300MW Pulverized Coal, Baseload Plant, in a Regulated Market	300	Pulverized Coal			Winter: $ 60 Spring/Fall: $ 50 Summer: $ 70	750	251
Plant 2 300MW Pulverized Coal, Baseload Plant w/ High Forced Outage Hours, in a Regulated Market	300	Pulverized Coal			Winter: $ 60 Spring/Fall: $ 50 Summer: $ 70	750	502
Plant 3 300MW Pulverized Coal, Baseload Plant w/ High Scheduled Outage Hours, in a Regulated Market	300	Pulverized Coal			Winter: $ 60 Spring/Fall: $ 50 Summer: $ 70	1500	251
Plant 4 300MW Pulverized Coal, Baseload Plant w/High Forced & Scheduled Outage Hours, in a Regulated Market	300	Pulverized Coal			Winter: $ 60 Spring/Fall: $ 50 Summer: $ 70	1500	502
Plant 5 300MW Pulverized Coal, Baseload Plant, in a Deregulated Market	300	Pulverized Coal			Winter: $ 80 Spring/Fall: $ 100 Summer: $ 120	750	251
Plant 6 300MW Pulverized Coal, Baseload Plant w/ High Forced Outage Hours, in a Deregulated Market	300	Pulverized Coal			Winter: $ 80 Spring/Fall: $ 100 Summer: $ 120	750	502
Plant 7 300MW Pulverized Coal, Baseload Plant w/ High Scheduled Outage Hours, in a Deregulated Market	300	Pulverized Coal			Winter: $ 80 Spring/Fall: $ 100 Summer: $ 120	1500	251
Plant 8 300MW Pulverized Coal, Baseload Plant w/High Forced & Scheduled Outage Hours, in a Deregulated Market	300	Pulverized Coal			Winter: $ 80 Spring/Fall: $ 100 Summer: $ 120	1500	502

Figure B-7.1

Study 7 Plants Being Investigated

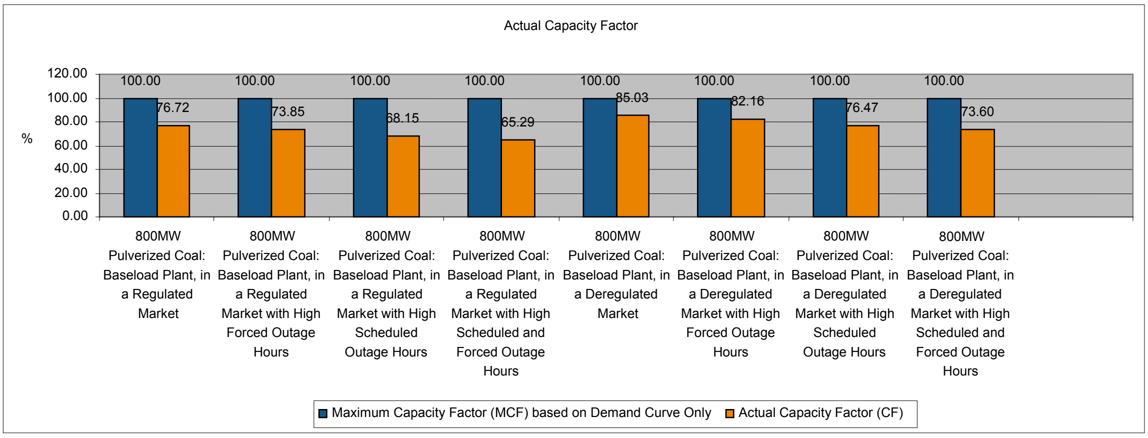


Figure B-7.2
Actual Capacity Factor

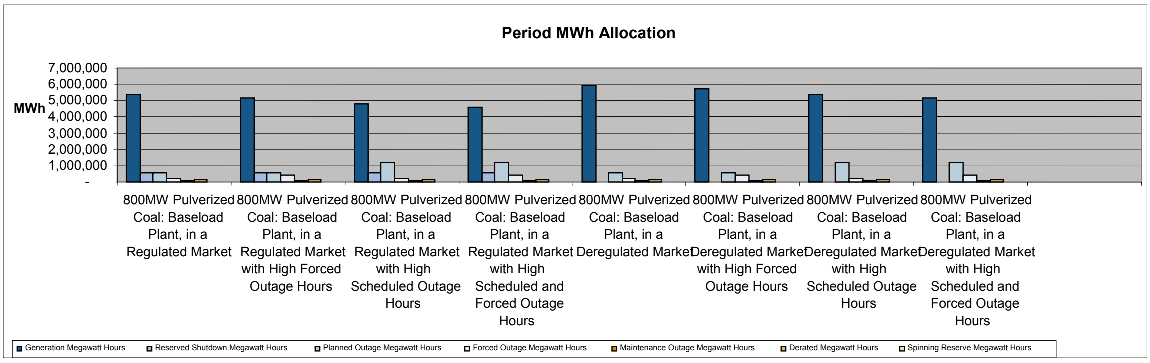


Figure B-7.3
Period MWh Allocation

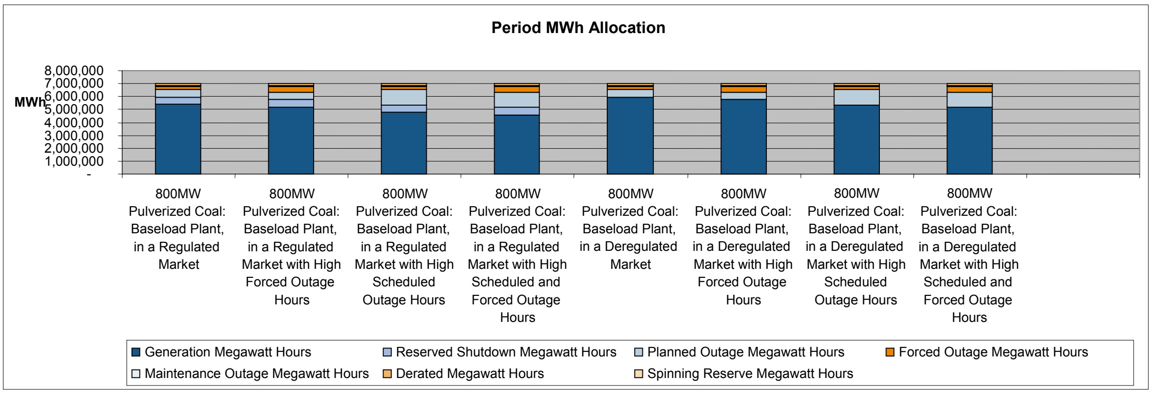


Figure B-7.4
Period MWh Allocation

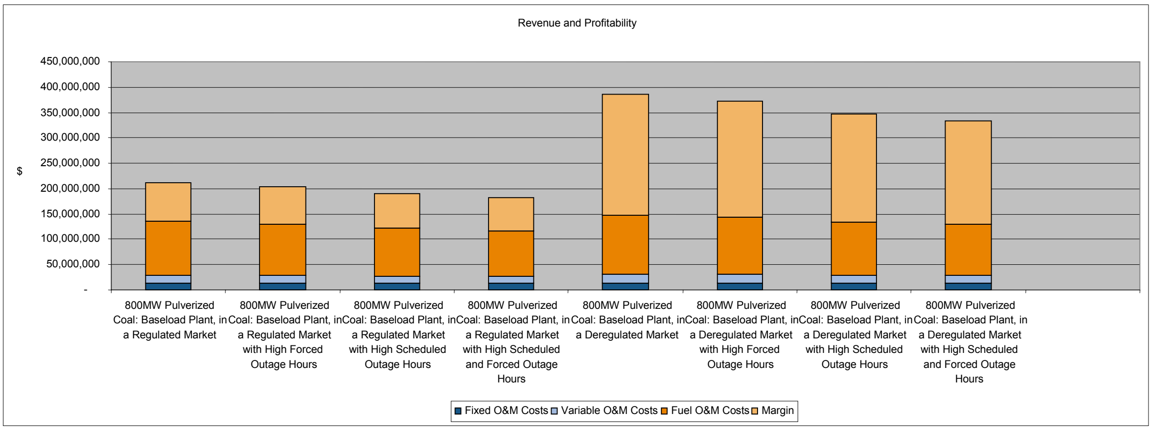


Figure B-7.5
Revenue and Profitability

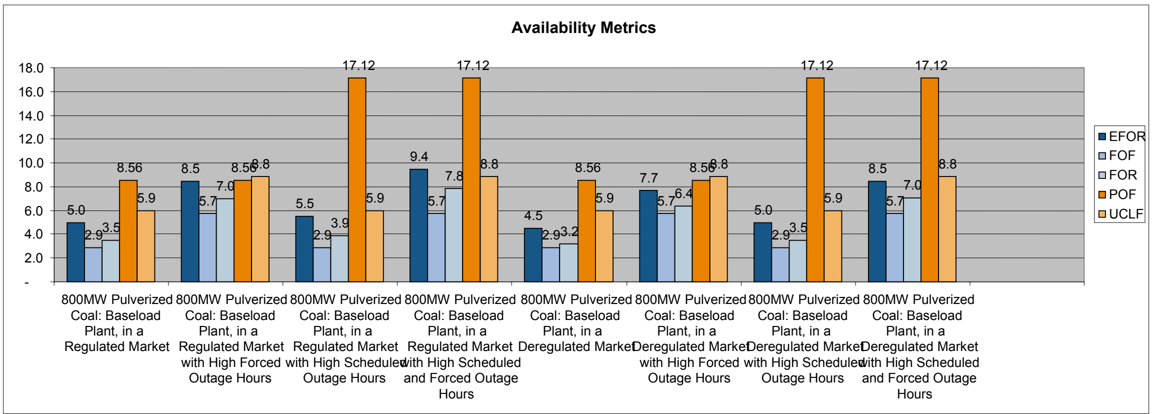


Figure B-7.6
Availability Models

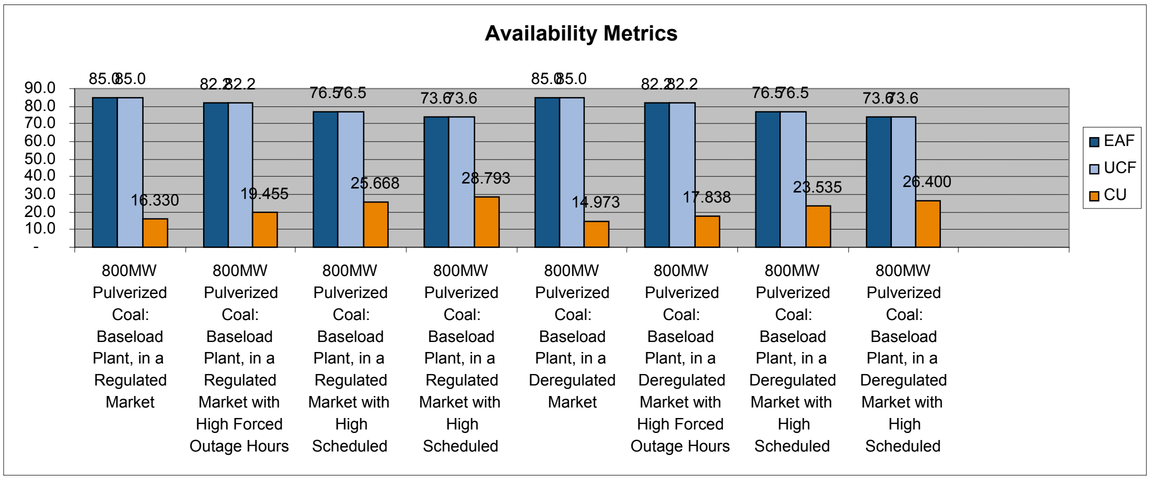


Figure B-7.7
Availability Metrics

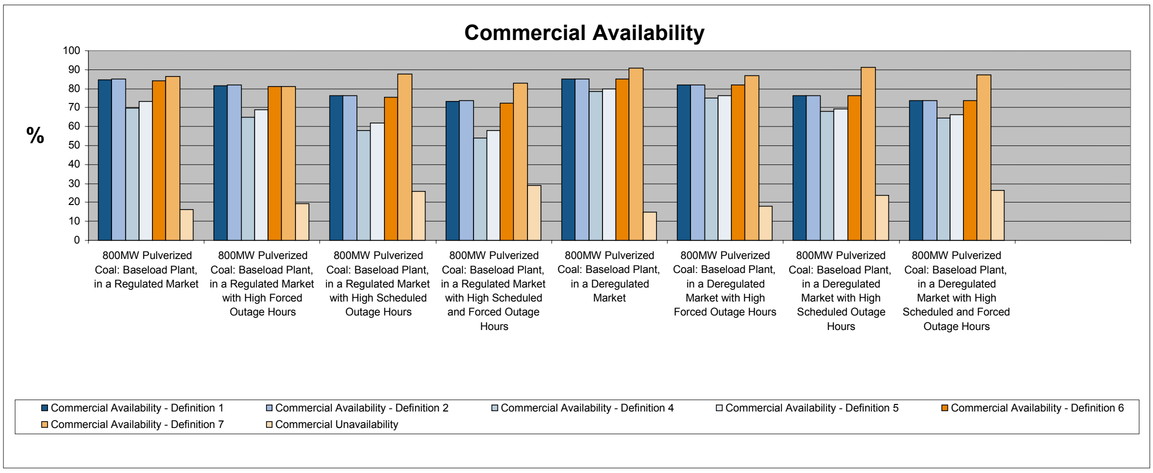


Figure B-7.8
Commercial Availability

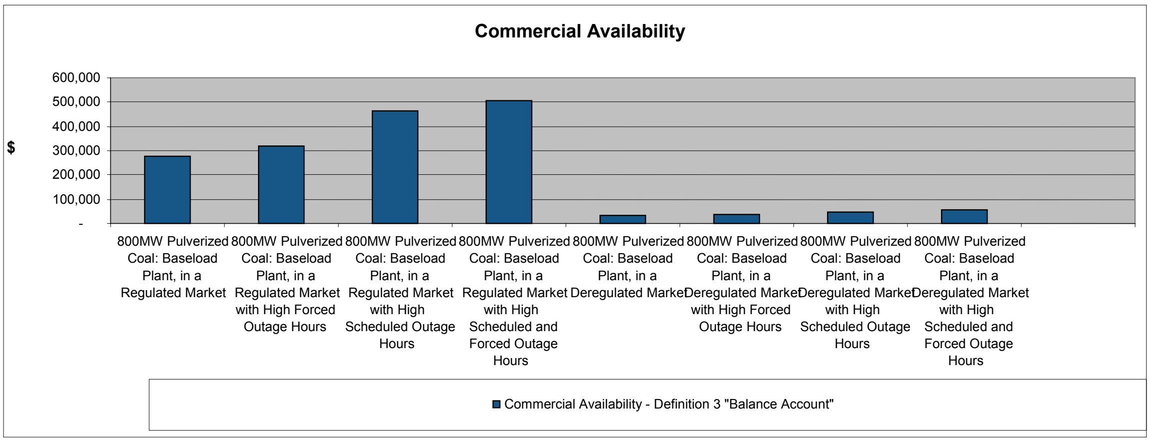


Figure B-7.9
Commercial Availability

Appendix C
PGP Screenshots

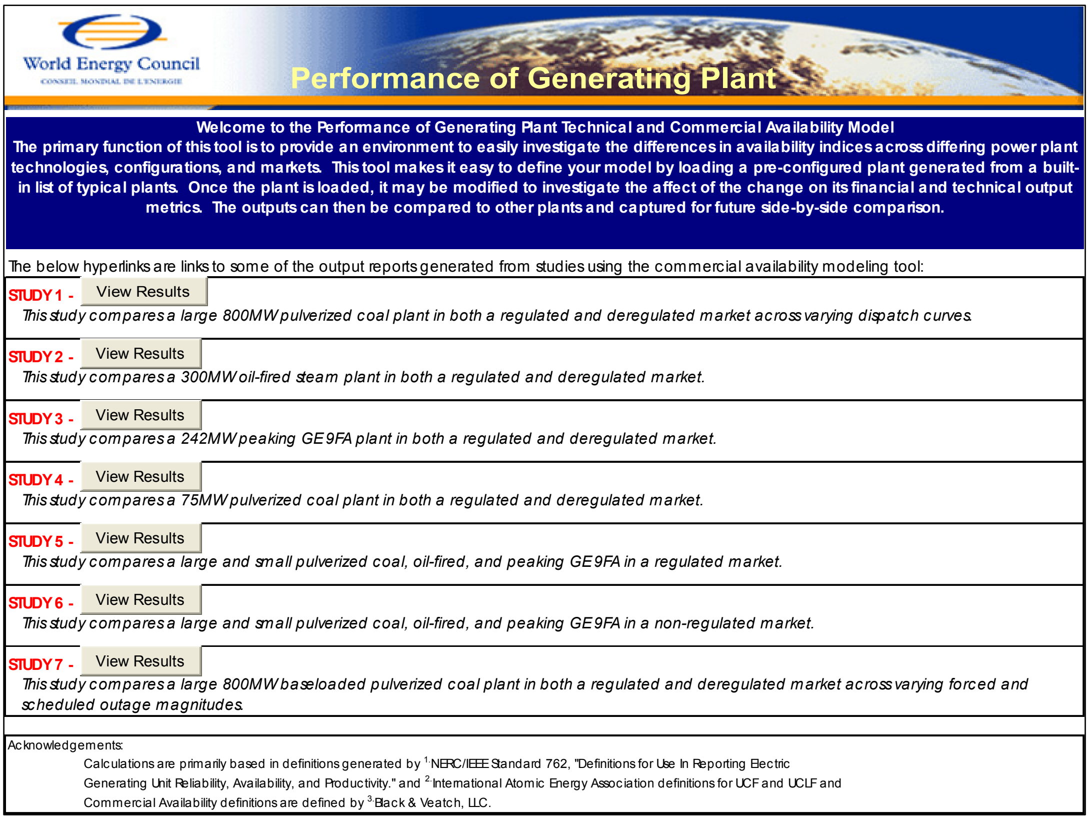


Figure C-1
PGP Main Screen

INPUTS:

Load Baseline Case to Current>> | Pulv coal 800 MW w/ Scrubber

View Profile Options

	Abbr.	Description	Units	800MW Pulverized Coal: Baseload Plant, in a Regulated Market	800MW Pulverized Coal: Baseload Plant, in a Deregulated Market
				PC 800MW BL-REG	PC 800MW BL-NONREG
	POF	Typical Price of Fuel	$/MBtu	$2.00	$2.00
Winter		Winter Demand Profile (1-9)		6	6
Winter		Winter Pricing Profile (1-4)		2	2
Winter		Winter Typical Peak Price of Power	$/MWh	$60.00	$80.00
Spring/Fall		Spring/Fall Demand Profile (1-9)		6	6
Spring/Fall		Spring/Fall Pricing Profile (1-4)		2	2
Spring/Fall		Spring/Fall Typical Peak Price of Power	$/MWh	$50.00	$100.00
Summer		Summer Demand Profile (1-9)		6	6
Summer		Summer Pricing Profile (1-4)		2	2
Summer		Summer Typical Peak Price of Power	$/MWh	$70.00	$120.00
	NMC	Net Maximum Capacity	MW	800.00	800.00
	NDC	Net Dependable Capacity	MW	800.00	800.00
		Season for Planned Outage Hrs (1-Winter,2-Spring/Fall,3-Summer)		2	2
Outages	POH	Planned Outage Hours	h	750	750
Outages	FOH	Forced Outage Hours	h	251	251
Outages	MOH	Maintenance Outage Hours	h	115	115
Counts	NOFO	# of Forced Outage Occurences		2	2
Counts	NOAST	# of Unit Actual Starts		4	4
Counts	NOATST	# of Unit Attempted Starts		1	1
Derate Hrs	PDH	Planned Derated Hours	h	164	164
Derate Hrs	FDH	Forced Derated Hours	h	418	418
Derate Hrs	FDHRS	Forced Derated Hours (during RS only)	h	1	1
Derate Hrs	MDH	Maintenance Derated Hours	h	200	200
Derate MW	SOPD	Size of Planned Derate	MW	200	200
Derate MW	SOFD	Size of Forced Derate	MW	200	200
Derate MW	SOFDRS	Size of Forced Derate (during RS only)	MW	200	200
Derate MW	SOMD	Size of Maintenance Derate	MW	200	200
NPHR	NPHR25	Manual 25% of Full Load NPHR	Btu/kWh	12,905	12,905
NPHR	NPHR50	Manual 50% of Full Load NPHR	Btu/kWh	10,664	10,664
NPHR	NPHR75	Manual 75%of Full Load NPHR	Btu/kWh	10,000	10,000
NPHR	NPHR100	Manual 100% of Full Load NPHR	Btu/kWh	9,848	9,848

Figure C-2
Input Screen

OUTPUTS:

			800MW Pulverized Coal: Baseload Plant, in a Regulated Market	800MW Pulverized Coal: Baseload Plant, in a Deregulated Market
MCF	Maximum Capacity Factor (MCF) based on Demand Curve Only	%	100.00	100.00
CF	Actual Capacity Factor (CF)	%	76.72	85.03
REV	Actual Revenue	$	210,457,080	386,193,040
FOMC	Fixed O&M Costs	$	12,880,000	12,880,000
VOMC	Variable O&M Costs	$	16,236,366	17,995,214
FUELC	Fuel O&M Costs	$	105,891,211	117,362,161
VFUELC	Total Fuel and Variable O&M Costs	$	122,127,576	135,357,375
TOTOMC	Total O&M Costs	$	135,007,576	148,237,375
PROFVF	Margin (not factoring Fixed O&M costs)	$	88,329,504	250,835,665
PROF	Margin	$	75,449,504	237,955,665
	Actual Revenue per MWh	$/MWh	39.15	64.81
	Fixed O&M Costs per MWh	$/MWh	2.40	2.16
	Variable O&M Costs per MWh	$/MWh	3.02	3.02
	Fuel O&M Costs per MWh	$/MWh	19.70	19.70
	Total Fuel and Variable O&M Costs per MWh	$/MWh	22.72	22.72
	Total O&M Costs per MWh	$/MWh	25.11	24.88
	Margin (not factoring Fixed O&M costs) per MWh	$/MWh	16.43	42.10
	Margin per MWh	$/MWh	14.03	39.93
EAF	Equivalent Availability Factor		85.0	85.0
EFOR	Equivalent Forced Outage Rate		5.0	4.5
$EFOR_d$	Equivalent Forced Outage Rate - demand		4.8	4.3
FOF	Forced Outage Factor		2.9	2.9
FOR	Forced Outage Rate		3.5	3.2
POF	Planned Outage Factor		8.56	8.56
UCF	Unit Capability Factor	%	85.0	85.0
UCLF	Unplanned Capability Loss Factor	%	5.9	5.9
CA1	Commercial Availability - Definition 1	%	84.716	85.040
CA2	Commercial Availability - Definition 2	%	85.027	85.027
CA3	Commercial Availability - Definition 3 "Balance Account"	$	278,330	31,509
CA4	Commercial Availability - Definition 4	%	69.936	78.688
CA5	Commercial Availability - Definition 5	%	73.361	79.826
CA6	Commercial Availability - Definition 6	%	84.297	85.034
CA7	Commercial Availability - Definition 7	%	86.366	90.866
CU	Commercial Unavailability	%	16.330	14.973
PH	Period Hours	h	8,760	8,760
PMWH	Period Megawatt Hours	MWh	7,008,000	7,008,000
GMWH	Generation Megawatt Hours	MWh	5,376,280	5,958,680
RSMWH	Reserved Shutdown Megawatt Hours	MWh	582,400	-
POMWH	Planned Outage Megawatt Hours	MWh	600,000	600,000
FOMWH	Forced Outage Megawatt Hours	MWh	200,800	200,800
MOMWH	Maintenance Outage Megawatt Hours	MWh	92,000	92,000
DMWH	Derated Megawatt Hours	MWh	156,520	156,520
SRMWH	Spinning Reserve Megawatt Hours	MWh	-	-
EFDH	Equivalent Forced Derated Hours	h	104	104
EFDHRS	Equivalent Forced Derated Hours During RS	h	0	0

Figure C-3
Output Screen

Maximum Capacity Factor (CF) Based on Plant Demand Curves, (Derates & Outages Ignored)[3]

This is the capacity factor that is calculated using the plant demand curve only. This ignores economic factors such as the price curve, and costs (fuel, fixed & variable O&M, etc.) It also does not factor in outages and derates.

$$MCF = \frac{\max\ MWh\ in\ operation\ using\ demand\ curve}{period\ MWh} \times 100 = \frac{MAXMWH}{PMWH} \times 100$$

			75MW Pulverized Coal: Varying Seasonal Dispatch Plant, in a Regulated Market	75MW Pulverized Coal: Varying Seasonal Dispatch Plant, in a Non-Regulated Market
	Max Winter MWh In Operation Using Demand Curve	MWh	113,175	113,175
	Max Spring-Fall MWh In Operation Using Demand Curve	MWh	202,395	202,395
	Max Summer MWh In Operation Using Demand Curve	MWh	133,950	133,950
MAXMWH	Max Megawatt Hours In Operation Using Demand Curve	MWh	449,520	449,520
PH	Period Hours	h	8,760	8,760
NMC	Net Maximum Capacity	MW	75	75
PMWH	Total Megawatt Hours In a Year	MWh	657,000	657,000
MCF	Maximum Capacity Factor (CF) Based on Plant Demand Curves, (Derates	%	68.4%	68.4%

Actual Capacity Factor (CF) Based on Dispatch Curve, Economics, Considering Outage, & Derate Hours[3]

This is the capacity factor after factoring in economics (using price curve to calculate revenue, then comparing revenue to fuel & variable O&M costs to see if operation is profitable), and taking out the outages and derated MWh.

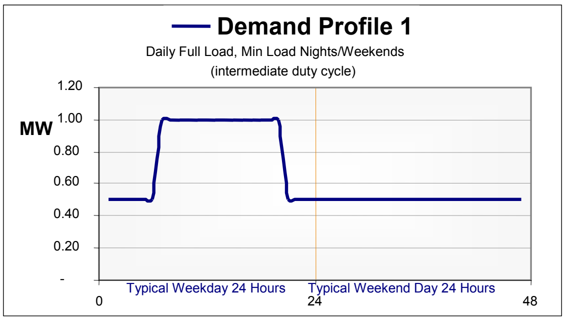
$$CF = \frac{econ\ MWh\ in\ service - MWh\ in\ outages\,/\,derates}{period\ MWh} \times 100 = \frac{ECMWH - POMWH - FOMWH - MOMWH - DRMWH}{PMWH} \times 100$$

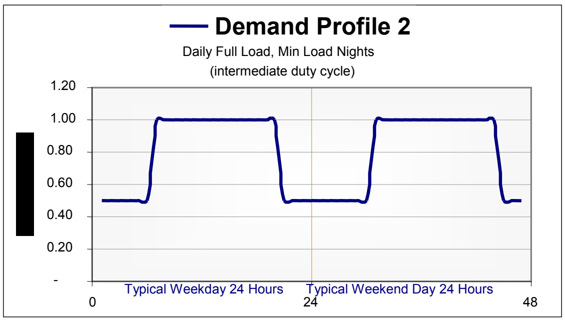
			75MW Pulverized Coal: Varying Seasonal Dispatch Plant, in a Regulated Market	75MW Pulverized Coal: Varying Seasonal Dispatch Plant, in a Non-Regulated Market
	Winter Actual Economic MWh In Operation	MWh	87,300	87,300
	Spring-Fall Actual Economic MWh In Operation	MWh	157,200	202,395
	Summer Actual Economic MWh In Operation	MWh	122,363	133,950
ECMWH	Total Economic Dispatch MWh in Service	MWh	366,863	423,645
	Winter MWh in Planned Outage	MWh	-	-
	Spring-Fall MWh in Planned Outage	MWh	40,950	40,950
	Summer MWh in Planned Outage	MWh	-	-
POMWH	Total MWh in Planned Outage	MWh	40,950	40,950
	Winter MWh in Forced Outage	MWh	5,984	5,984
	Spring-Fall MWh in Forced Outage	MWh	11,369	11,369
	Summer MWh in Forced Outage	MWh	5,930	5,872
FOMWH	Total MWh in Forced Outage	MWh	23,283	23,225
	Winter MWh in Maintenance Outage	MWh	3,543	3,543
	Spring-Fall MWh in Maintenance Outage	MWh	6,732	6,732
	Summer MWh in Maintenance Outage	MWh	3,511	3,477
MOMWH	Total MWh in Maintenance Outage	MWh	13,786	13,751
	Winter MWh in Derate	MWh	3,655	3,655
	Spring-Fall MWh in Derate	MWh	6,944	6,944
	Summer MWh in Derate	MWh	3,622	3,587
DRMWH	Total MWh in Derate	MWh	14,221	14,186
	Total MWh in Planned Outage	MWh	40,950	40,950
	Total MWh in Forced Outage	MWh	23,283	23,225
	Total MWh in Maintenance Outage	MWh	13,786	13,751
	Total MWh in Derate	MWh	14,221	14,186
	Total MWh in Outage or Derate	MWh	92,240	92,112
	Actual MWh in Service	MWh	274,623	331,533
NMC	Net Maximum Capacity	MW	75	75
PH	Period Hours	h	8,760	8,760
PMWH	Maximum MWh In a Year	MWh	657,000	657,000
CF	Actual Capacity Factor	%	41.80%	50.46%

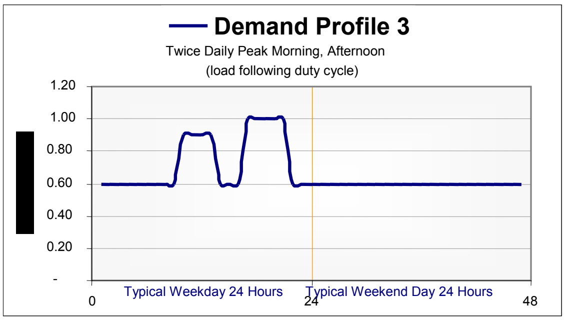
Figure C-4
Calculations Screen

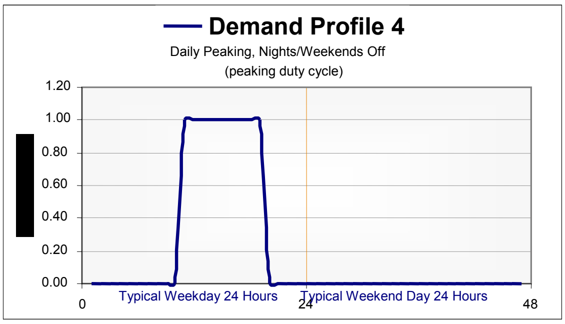
Appendix D
Demand Profiles

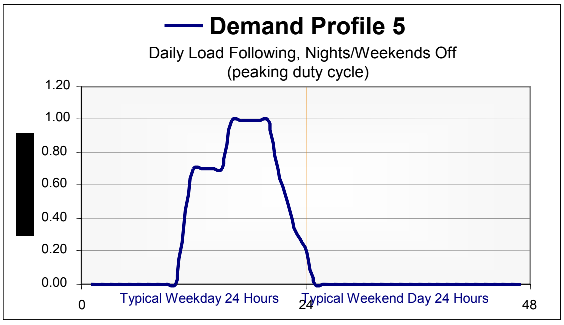
This appendix contains a complete collection of available demand profiles found within the PGP Profile

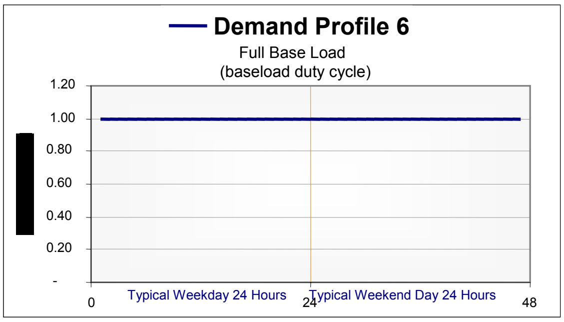


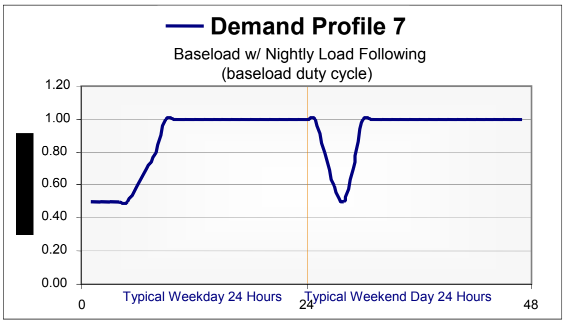


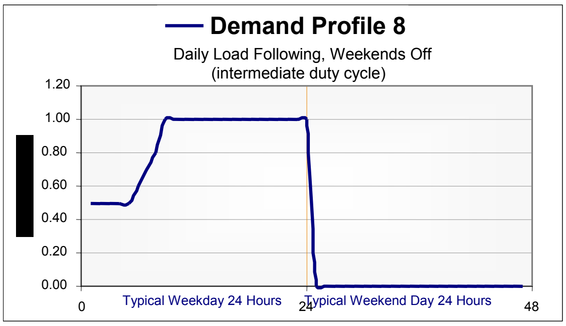


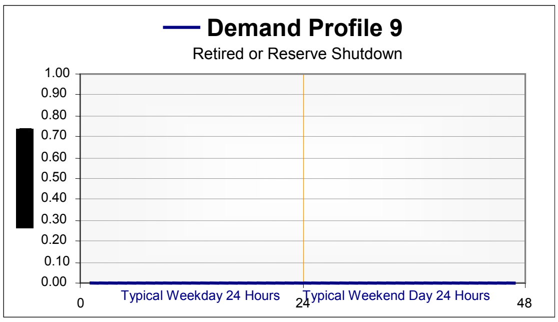



Demand Profile 5
Daily Load Following, Nights/Weekends Off
(peaking duty cycle)
1.20
1.00
0.80
0.60
0.40
0.20
0.00
0
24
48
Typical Weekday 24 Hours
Typical Weekend Day 24 Hours


Demand Profile 6
Full Base Load
(baseload duty cycle)
1.20
1.00
0.80
0.60
0.40
0.20
-
0
24
48
Typical Weekday 24 Hours
Typical Weekend Day 24 Hours

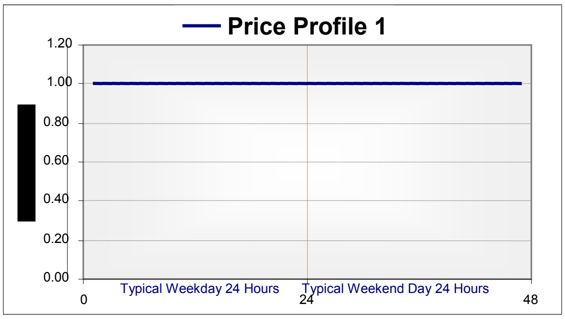

Demand Profile 7
Baseload w/ Nightly Load Following
(baseload duty cycle)
1.20
1.00
0.80
0.60
0.40
0.20
0.00
0
24
48
Typical Weekday 24 Hours
Typical Weekend Day 24 Hours

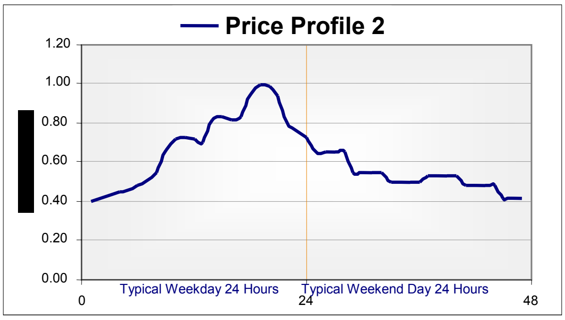

Demand Profile 8
Daily Load Following, Weekends Off
(intermediate duty cycle)
1.20
1.00
0.80
0.60
0.40
0.20
0.00
0
24
48
Typical Weekday 24 Hours
Typical Weekend Day 24 Hours

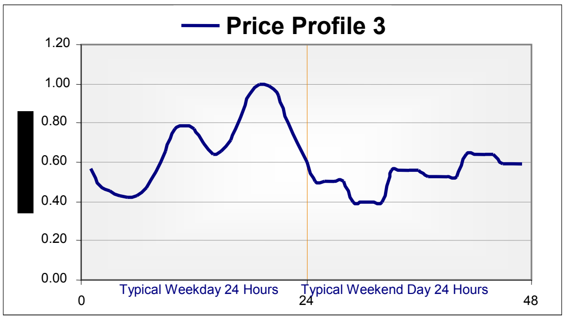

Demand Profile 9
Retired or Reserve Shutdown
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
0
24
48
Typical Weekday 24 Hours
Typical Weekend Day 24 Hours

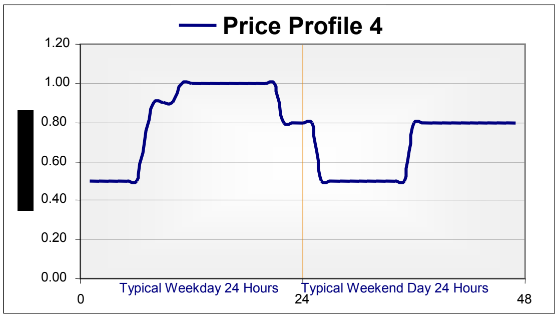
Appendix E Price Profiles

This appendix contains a complete collection of available market price profiles found within the PGP Model.









Appendix F
Output Trends

Figure 2 is used to compare how each of the plant's period MWh is spent.

Figures 3 and 4 provide a comparison of traditional availability and capability metrics. Figure 3 displays metrics including Equivalent Forced Outage Rate (EFOR), Forced Outage Factor (FOF), Forced Outage Rate (FOR), Planned Outage Factor (POF), and Unplanned Capability Loss Factor (UCLF). Figure 4 displays metrics including Equivalent Availability Factor (EAF), Unit Capability Factor (UCF), and Commercial Unavailability (CU).

Figure 6 and 7 illustrate the comparison of the revenue and profitability between each of the plants. Figure 6 is a stacked chart that demonstrates the overall revenue $ and where it is used. Figure 7 is the same values, but displayed on a percentage basis.

There are a few additional charts that are generated for the current plant being investigated. One of which is Figure 8, which illustrates the portions of the period where it is not economical to operate the plant, since the costs are higher than the revenues being generated. The plant does not generate MW during these periods and this can be seen when the red line drops to zero. These are the times when the market price is not high enough to generate enough revenue to offset the costs.

The "Crv MW" line (blue line) is a trend of the MW profile that was chosen for that particular season. The "Actual MW" and "Crv MW" would be the same if the market price was high enough that the plant generated at all times throughout the period. As seen before, this chart is separated into 48 hours along the X-axis, the first 24 hours being a typical weekday, and the second 24 hours representing the typical weekend day. The chart below shows us that during the Spring/Fall, this plant will operate all hours during weekdays except from 12:00AM to 4:00AM, and it will operate all hours on weekends, except from 9:00PM to 12:00AM. It will not operate during those times because the revenues are not high enough to justify doing so.

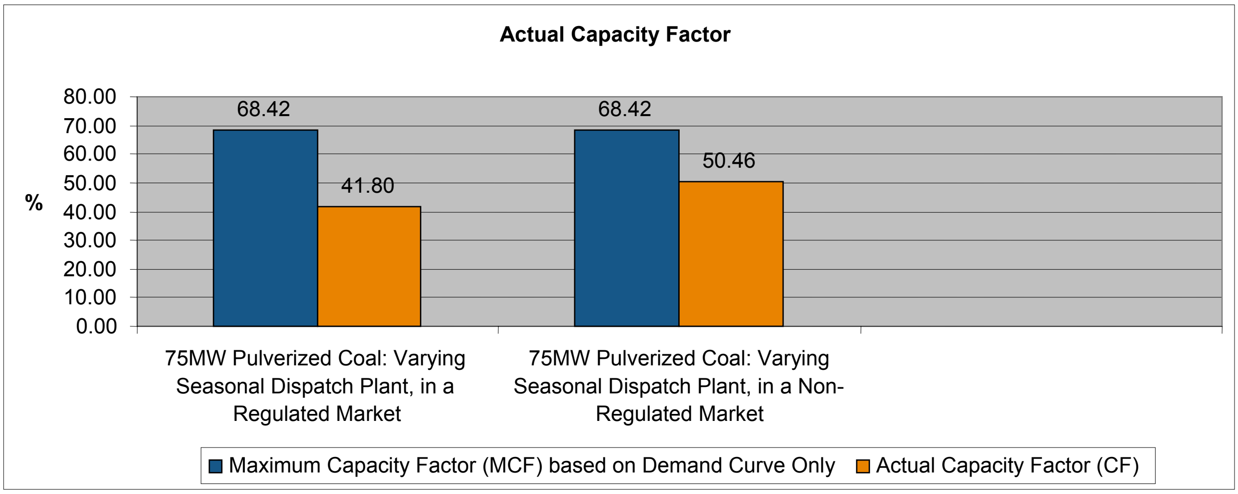


Figure F-1

Plant Actual Capacity Comparison Factors

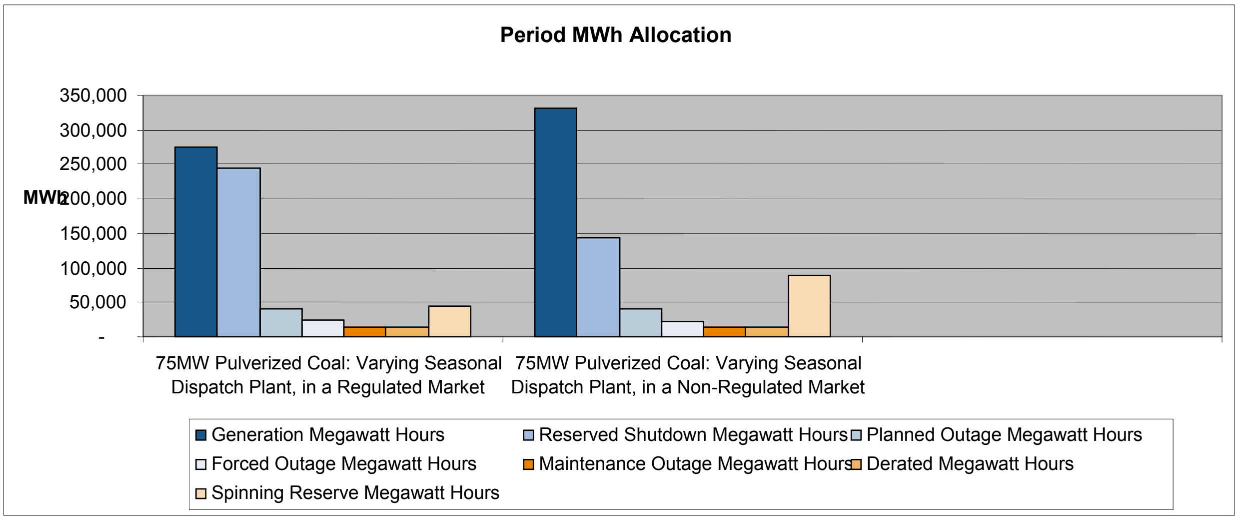


Figure F-2

Plant Period MWh Allocation Comparison

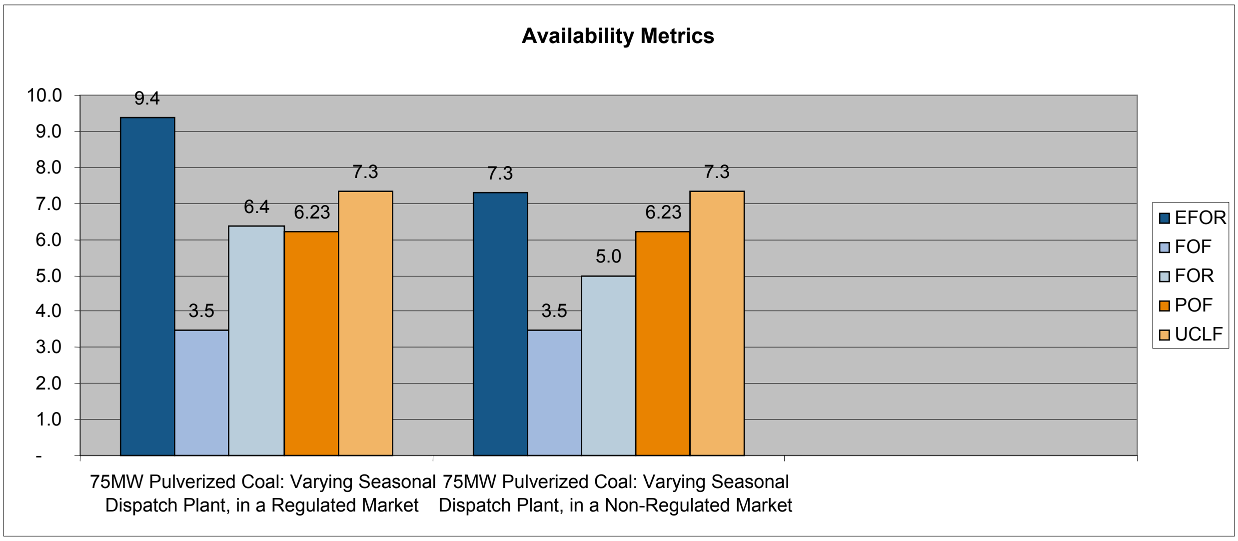


Figure F-3

Plant Traditional Availability and Capability Metrics Comparison

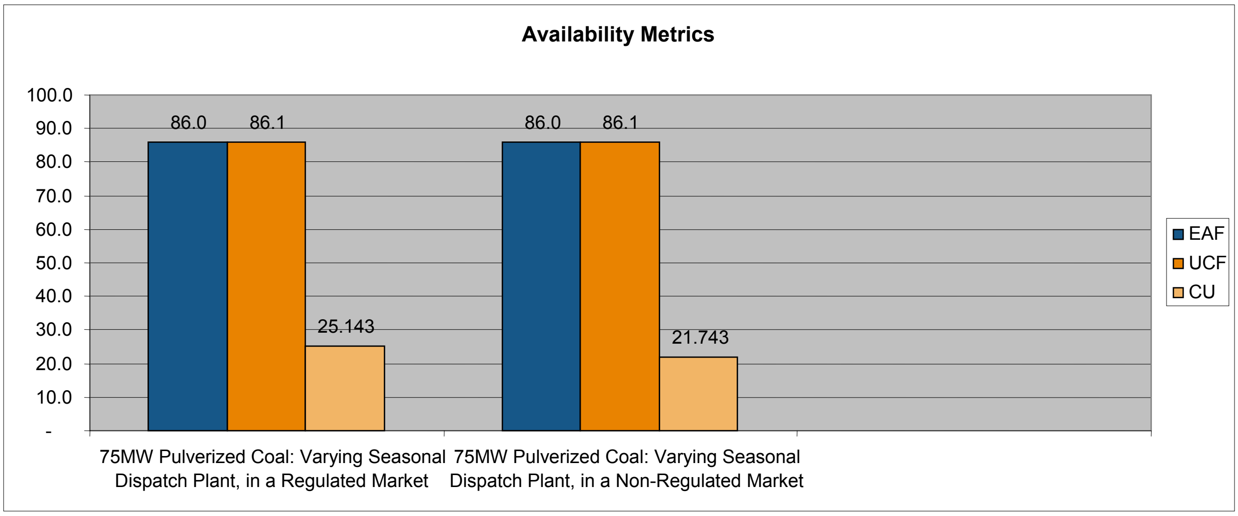
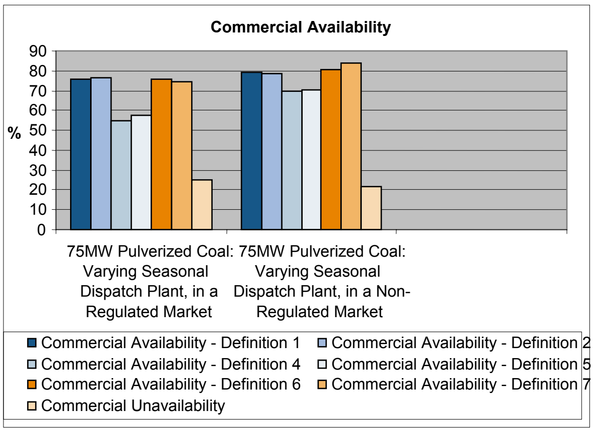


Figure F-4
Plant Traditional Availability and Capability Comparison



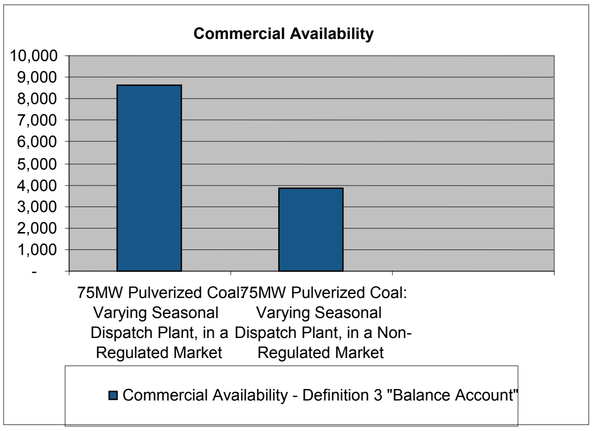


Figure F-5
Plant Commercial Availability Comparison

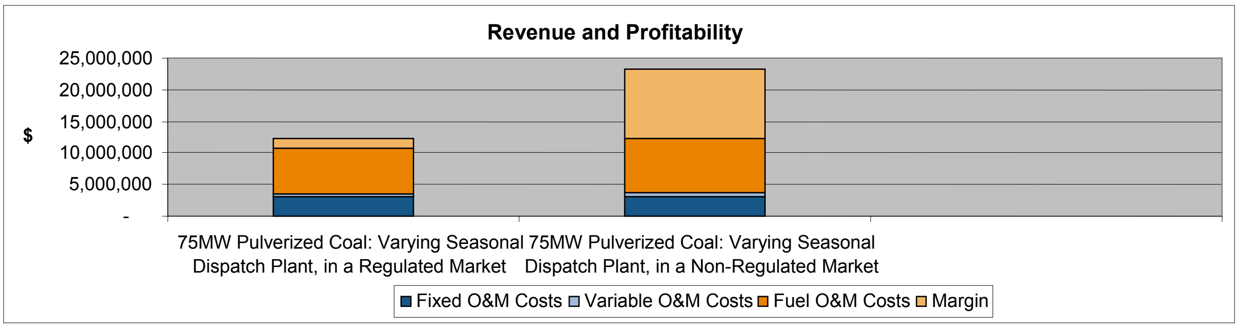


Figure F-6
Plant Revenue and Profitability Comparison

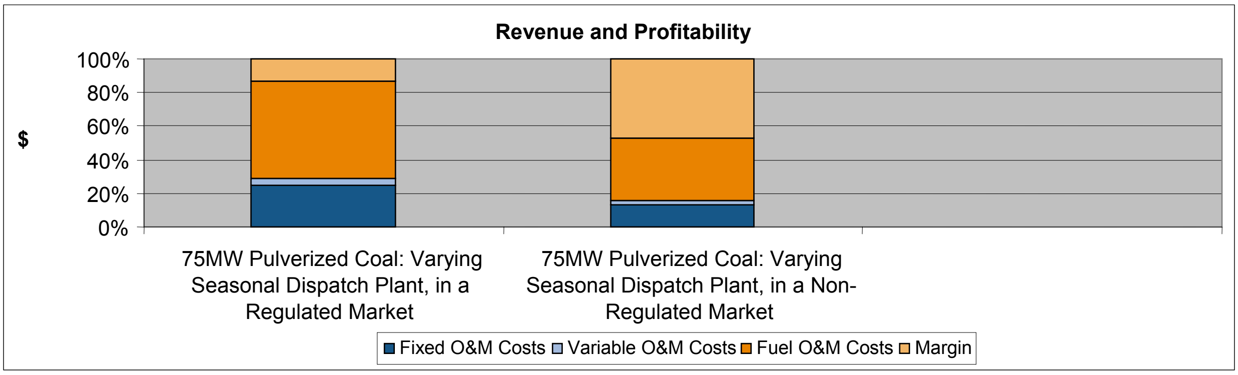


Figure F-7

Plant Revenue and Profitability by Percentage

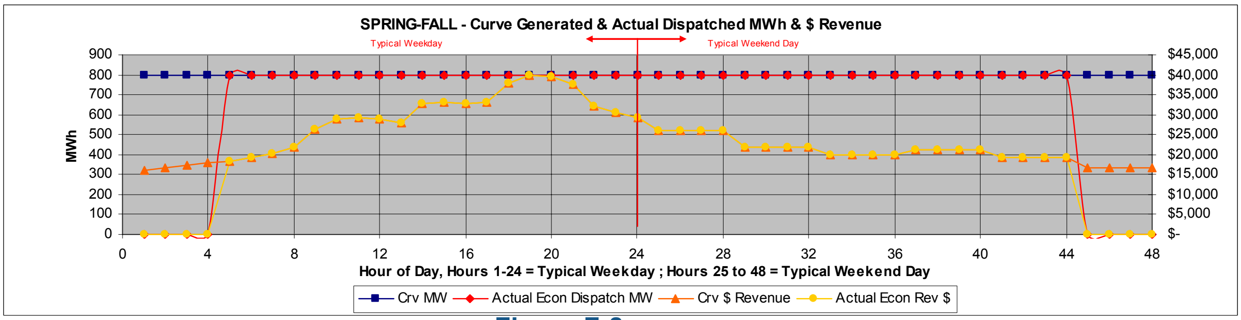


Figure F-8

Seasonal Dispatched MWh.

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