Spring 2012

# A business case for electric power distributors using simulation: Investigating the combined use of the strategies of feed-in-tariffs, distributed generation, time of use rates, and efficiency

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# A Business Case for Electric Power Distributors Using Simulation :Investigating the Combined Use of the Strategies of Feed-In-Tariffs, Distributed Generation, Time of Use Rates, and Efficiency

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A thesis submitted to the Graduate Faculty of

JAMES MADISON UNIVERSITY

In

Partial Fulfillment of the Requirements

for the degree of

Master of Science

Integrated Science and Technology

April 2012

## Acknowledgments

There are many people that have contributed to this project and thesis in multiple ways that I wish to thank.

First and foremost is my wife, Pilar. Without her patience and perseverance through this grand adventure, I would not have enjoyed the opportunity I have experienced here at James Madison for the last two years.

Second, I wish to thank my children for having put up with my nerdiness and the crazy idea of going back to school. They have been very supportive and attentive throughout the entire process.

Third, I would like to thank my friend, professor, mentor, and Thesis Chair, Dr. Michael Deaton. His patient teaching and willingness to take on my projects has been key to my successes and helpful in my failures. Having exposed me to the world of System Dynamics is a fact that I will always remember and benefit from for years to come.

Next, I sincerely thank the remaining members of my Thesis Committee:

Dr. George Baker

Mr. Paul Goodall

Dr. Nicole Radziwill

They are all extremely engaged professors and their willingness to take on one more thesis means a great deal to me.

I thank Mr. Brian O'Dell of Harrisonburg Electric Commission. His willingness to provide time, energy, and information was a critical part of this thesis. I would not have been able to reach even the limited level of success I did without him.

Finally, there are numerous individuals that contributed to the project by providing input, data, and general ideas that were all pondered as I meandered through the development of this project. These people were professors, fellow graduate students, friends, and acquaintances that willingly answered my questions and provided advice and insight. To think that a project such as this can be undertaken without the help of others is naive and pretentious. I am humbly grateful for all of their help.

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## Abstract

Numerous references found in the academic and trade literature discuss the availability and applicability of certain technologies and policies to allow the U.S. electrical grid to address the future challenges of continued growth and aging infrastructure. However, the existing utility companies seem reluctant to adopt these new measures. This thesis will describe some of these strategies and develop a model using Stella system dynamics software that will explore the potential financial impact to the utilities from using these strategies in combination. The four strategies to be investigated are feed in tariffs, time of use rates, distributed generation, and demand-side energy efficiency .

There are other strategies that could be considered such as Renewable Portfolio Standards, Net Metering, Critical Peak Pricing, and Renewable Energy Tax Credits. These other strategies are either similar in implementation to the four discussed in this paper or have been shown to not have lasting affect on the utility industry's bottom line. For this reason, the four listed above have been chosen.

From the research and the test case data used in this paper, the following findings were observed:

- Distributed Generation will most likely not be implemented without some true incentive to the owner and without a policy such as Feed-In Tariffs.
- Energy Efficiency practices can significantly reduce electrical consumption. Specific technologies have very attractive payback or return on investment and others are not practical when only taking into account ROI measurements.
- Peak Shifting or Peak shaving can have significant effect on the utility's profit but has no effect on the consumer's electricity bill.
- Time of Use rates have very different effects on the utility. Depending upon the cost structure of their generation and the nature of its customer load, the TOU rate can significantly reduce the profit of the utility even without Peak Shifting.
- The biggest positive impact for society as a whole would be a policy that lowers electrical consumption, decreases the release of greenhouse gases, and allows the utility to remain a viable business. The combination of strategies

that offers this impact would be the use of Peak Shifting with no TOU rates, demand-side Energy Efficiency, and the implementation of a FIT for photovoltaic generation.

## Introduction

The purpose of this thesis is to describe and simulate the effects of the four strategies of feed-in tariffs, time-of-use rates, distributed generation, and energy efficiency on the Harrisonburg Electric Commission (HEC), a municipally-owned distributor of electricity. The goal is to determine the effects of these policies on HEC profits, its customers' electric bills, and the total residential consumption of electricity within HEC's service area. The principles and functionality used in this model can serve as a template for application to other regions of the United States and other electricity distributors.

HEC is a relatively small electricity distributor with loads ranging from about 55 MW up to 130 MW. In comparison, a large coal-fired generating plant can generate well over 400 MW. HEC's customer base of about 20,000 accounts is made up of industrial, commercial users as well as approximately 17,000 residential customer. It was formed in 1957 as a way to consolidate smaller generating plants and provide wholesale buying power to the local Harrisonburg area. Because of their size, HEC purchases over 99% of its power from larger, regional utilities under a multi-year contract.

## Energy versus Electricity

Throughout the literature the terms 'energy' and 'electricity' are used interchangeably. Both terms are used numerous times throughout this paper. For this paper, because the discussions of electricity are entwined in discussions of energy in general, the term electricity represents a subset of the term energy and is not considered interchangeable. All efforts are made to keep this usage consistent in regards to citations in the literature and in this author's discussions.

## A Brief History

The United States has built a complex yet impressive infrastructure for its electrical demands since the early $20^{th}$ century. Vertically integrated utilities were able to grow virtually unimpeded in the first 25 years of the 1900's. As generating plants became larger and more efficient, more industrial generators (non-utilities) gave up their smaller generating capacity because it was economically beneficial and more convenient. Smaller utilities merged with larger to increase their territory. The utilities were handed near-monopolistic control over ever growing transmission networks. As these territories grew past state lines, the federal government began to exercise its authority. In the 1930's and 1940's, the federal government passed new laws regulating investor-owned utilities, pressed for broader electrification in the U.S., and began several large hydroelectric projects that put the government in the power business. Demand for electricity grew every year, even during the Great Depression. Prices steadily dropped and despite new government oversight, the utility industry continued to grow.

Until the late 1960's, demand continued to grow and prices dropped by achieving economies of scale through growing capacity. By then, market saturation was high and utilities began to see costs rise as growth slowed and the economies of scale leveled off. Large projects cost more due to the rise of inflation, pollution control requirements from the newly formed EPA, and higher input costs from the energy price shocks in 1973 and 1979. New generating plants already under construction began to come online. For the first time in 70 years, capacity margin (the difference between capacity to generate and actual generation) began to balloon. In 1982, actual generation or total consumption actually shrank for the first time since 1945. Economic slowdown and savings due to increased efficiency in electricity use contributed to this drop in consumption. As a result, the utility industry put the brakes on capacity expansion and began to idle some plants. However, demand growth recovered quickly and capacity margin began to shrink again because utilities did not reinstate their planning processes[1]. Not until the early 2000's did the capacity margin begin to grow again[2] due to an increase in smaller and more nimble gas generators. Also, capacity increases resulted from new producers entering the market as new regulation enticed or even forced vertically integrated utilities to de-couple their generation capabilities from their retail distribution and other business services. This de-coupling allowed the new non-utilities to compete in the electricity markets. Summer capacity margin, a significant measure of reliability, has remained mostly between 15% and 20 % each year since 2004 after falling for the previous 15-20 years.

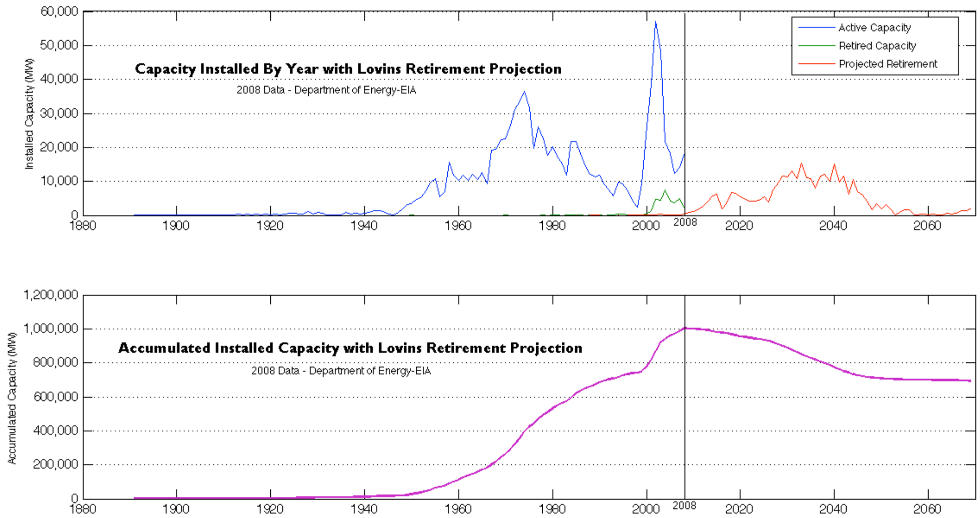


**Figure 1 - Historical and Projected Trends for Generation Capacity in the U.S.** The upper graph shows three trends; the amount of capacity that is still operating graphed vs installed year, the amount of non-operating, retired capacity vs retirement year, and the projected coal-fired, retired, coal-fired capacity vs retirement year if all coal-fired plants operate for 60 years. The lower graph shows the total or accumulated capacity in operation until 2008 and the effects on capacity of retiring the coal-fired plants as they reach age 60.

## The Current Situation

On the supply side of the electricity equation, the question remains whether the continued growth in demand can be met. The utility industry faces an aging infrastructure, higher construction costs, longer delays for permitting new plants, and an unknown future with regards to government policy and demand growth. Many in the industry and academia acknowledge that the existing infrastructure consisting of large scale generating plants and transmission and distribution lines is aging and fraying under the steady growth of electrical demand with few realistic plans for upgrades and improvements[3-5]. For example, even if utilities were to operate all of their coal-fired power plants to the age of 60 (twice their normal accounting life), 94% of them would be retired by 2050. Since coal-fired plants provide more than 30% of the nation's electricity, the loss of these units will leave a large gap in the national capacity. The lower graph of ***Figure 1*** (above) shows what the installed capacity might look like under this scenario. Summer capacity margin would reach critical levels if large amounts of new generation are not installed in the next 15-20 years. Addressing this one issue will be a daunting and expensive task[6]. The aging U.S. electrical grid is becoming less reliable due to these problems of continued growth and very little new capacity[7; 8].

The question is whether the electric power industry can remain profitable while maintaining and improving the required infrastructure. Undertaking new plant construction in the large, centralized style of the past requires utilities to apply to the regulators for the ability to pass the new costs on to the customers. Most rate structures for electricity distributors are based upon the value of their installed assets such as generating plants and transmission and distribution systems. In the 1980's, in order for the utilities to include new plants in their asset base, the regulators applied the standard known as 'used and useful'. The implication was that the new plant had to have a higher economic value than its true accounting cost. This standard was used to keep utilities from building unnecessary plants just to increase their asset base in times of electricity supply surplus. This strict standard made it difficult for utilities to add new capacity. One effect of this standard was to contribute to the continued decline in new plant construction as indicated above in the upper graph of ***Figure 1***[9]. Other contributors to the dearth of construction were the long term uncertainties of the electricity markets, policy changes that came with constantly changing administrations at the federal and state level, and higher borrowing costs that resulted from investors being unsure about the quality of the investment[10].

From the 1920's until the 1990's, electricity was treated as a commodity by utilities, consumers, and policymakers[11]. It did not matter where the electricity came from as long as it was cheap and available at the flip of a switch. In 1970, the fraction of U.S. total energy use that was electricity was 25%. By 2007, it was 40%[12]. This trend is expected to continue due to the continuing transformation of the U.S. economy from heavy industry to more service-oriented businesses. One indicator of this commodity viewpoint is what Polimeni calls the Economic Energy Intensity (EEI) index. The EEI is the ratio of total energy consumption to the Gross Domestic Product or the amount of energy required to produce a dollar's worth of goods[13]. This index has shown a 50% decrease from 1949 to 2004 resulting from the reduced value of energy inputs in the economy. Energy inputs became cheaper because of more efficient production methods and more competition from world-wide producers of oil and coal. ***Figure 2*** (below) shows the trend of the EEI with what U.S. Department of Energy labels E/GDP. However, the Total Energy Consumption (TEC) counteracts the point by having tripled in the same time span [13; 14]. This trend is indicated in ***Figure 2*** by the line labeled Energy. The TEC measures the total of all energy consumption. If the TEC continues to climb then the GDP must climb even faster to produce the downward trend of the EEI. During the period from 1949 to 2004, the graph indicates the nation's GDP has grown by a factor of eight thus making EEI lower over time. Just as with any commodity, the U.S. has become less concerned about the source of the energy it consumes as the energy becomes less economically significant as indicated by the EEI downward trend.

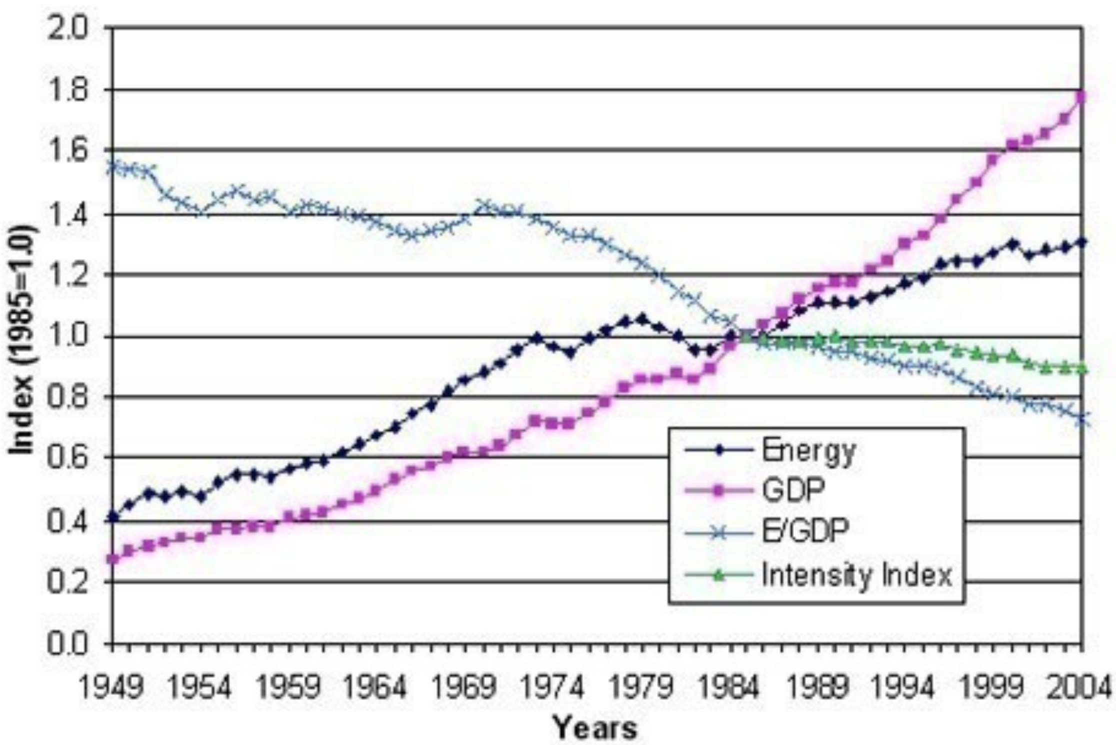


***Figure 2- Historical Trends for Energy Consumption, GDP, and Intensity*** *This graph, produced by the Department of En-*

*ergy, shows trends in total energy consumption (labeled Energy), GDP, and the normal Economic Energy Index (E/GDP). The graph's declining Intensity Index indicates energy efficiency improvements over the time span [13].*

During the 1990's, new concerns about our energy use arose from two basic issues. The first concern was the continued instability in the price and access to our energy inputs. Because of society's dependence on fossil fuels, geopolitical turmoil and threat of supply shortage created insecurity in the U.S. Rapid growth of the so-called BRIC countries (Brazil, Russia, India, and China) increased the global demand for oil and other fossil fuels. Since fossil fuels are still used to generate over 69% of the electricity in the U.S., the global fossil fuel economy is central to much of our foreign policy today.

The second concern about U.S. energy consumption was the growing body of evidence suggesting an increased anthropogenic effect on the earth's climate from fossil fuel use. As more research was produced, the concern continued to grow which has lead to global efforts to mitigate the further burning of fossil fuels and the resulting greenhouse gases (GHG). Again, geopolitical issues are at the forefront of the climate change concerns because of the BRIC growth in demand but here in the U.S. there is little political will to address the problems in any meaningful way. Global initiatives make little difference in how we use energy. Legislation is proposed but never passed. Groups of Americans speak out but are never heeded. New technologies will be necessary to reduce the amount of GHG emissions into the atmosphere. Many climate models show that large reductions will be needed to slow the increase of $CO_2$ to levels that even the conservative predictions say we need. How can this concern be addressed?

## The Path Forward

In the past, the U.S. energy policy was simple; provide cheap electricity to as many people as possible and let it serve as the lifeblood of a growing economy. Now, with these new concerns, our energy policy must address three strategic goals: energy must be cheap, secure, and clean[15].

## Policy Goal: Cheap Energy

The United States still needs a source of cheap energy to feed its demand. The projected electricity demand growth rate is more than 1% every year for the next 28 years[3]. Electricity will continue represent between 40% and 50% of the total energy consumption in the U.S. over the same time period.

## Policy Goal: Secure Energy

As a result of turmoil in oil-exporting countries in the Middle East and Africa and natural disasters such as the 2010 oil spill in the Gulf of Mexico, the U.S. is heavily dependent on energy sources that it cannot completely control. These factors relating to security will continue to add a price to the cost of our cheap energy.

## Policy Goal: Clean Energy

Societies have always increased their desire for a healthy life as affluence increased. An example of this desire was the transition from steam locomotives to diesel locomotives because they were cleaner and allowed traveling to be more enjoyable and our cities to be less sooty. Another example is the demand for cleaner places to live which drove the migration from the cities to the suburbs in decades past [15]. Since the 1970's, America has become increasingly aware of the societal costs of pollution to our air and water. Now, with the increasing concern over the effects of climate change, the clean requirement has taken on new meaning. There is more desire to limit the burning of fossil fuels to generate electricity or to do other things that could be done in a cleaner way with electricity.

### Market Based Approach

For the past 35 years, our government chose to deal with these policy concerns with privatization, liberalization, and competition. Beginning with Public Utility Regulatory Policies Act (PURPA) in 1978 and following with other major legislation like the Energy Policy Act of 1992, the federal government attempted to unlock the electric utility monopolies and push new technology into the marketplace. The idea was that the electric utility industry needed to be opened to competition and allow market-based reforms to take hold. This approach presupposes that investment in new technology or capacity will occur when the investments can be driven by potential profits and the competition for them.

There are a number of problems with this policy. Electricity cannot be stored until the market chooses to pay the required price. Therefore there must be excess generating capacity because there is no 'inventory' to draw from in times of shortage. This problem requires the utilities to have different types of capacity online, ready to produce. The nature of these quick-response generators or 'peak load' producers is that they are more expensive to operate. To pay for the peak load producers, the regulators must allow the utilities to pass these costs through to their customers or risk not having them built. The risk is measured in the difference between supply and demand side perceptions. The cost of electricity shortages to the utility is simply the loss of a sale. The cost to the customer might be extremely high. If a factory relies on electricity to run its process 24 hours per day, then losing that supply could mean huge recovery costs from damage to the process as well as lost sales. This lack of balance requires policy intervention because the utilities risk much less than their customers by failing to provide adequate supply during these peal loads. The regulators, not the markets, must provide the balance between the supplier and customer.

Another problem with the existing policy, is that electricity requires a network (the electric grid) for distribution which is considered a public necessity by all. Because most utilities enjoy near-monopolistic power, this public need is usually not managed in an equitable way and thus requires policy intervention. If one company owns a particular transmission line, then there needs to be some incentive or regulation that pushes the utility to allow access to the transmission line by other companies that also generate electricity. This requirement is especially important with generation such as wind turbines that have a regional propensity. In order for the electricity to get to the enduser, it must be transmitted a long distance over wires that the generating company might not own.

Lastly, the marginal price (the incremental cost to produce one additional unit of something) of oil is much lower than the actual OPEC-driven price of oil. In other words, the cost to produce an additional barrel of oil after the well is in place is much less than the price set by the OPEC organization. This price distortion in the market also affects the cost of natural gas and coal. This effect is caused by the world economy constantly balancing the cost of a BTU, a basic unit of energy. The market value for a BTU is the same independent of its source in the short term. The source could be coal, oil, gas, as well as other possibilities such as nuclear or even solar thermal in some cases[16]. These distortions make it difficult for utilities to project costs into the future. Contracts to purchase energy have become hedges against possible price shocks which allows speculators and other non-energy industries to affect the price of energy.

In summary, the traditional market driven policies for electricity have not allowed the balancing between supply and demand necessary to address the three goals of cheap, secure, and clean electricity. The investment that is necessary to make these policies work is too risky to investors. Unknown growth in demand, unpredictable energy prices, and the regional monopolies of the existing utilities create a business environment in which few companies want to compete. While the demand is projected to continue to grow well into the 21$^{st}$ century under most model scenarios, the existing utilities have little motivation to adapt to the new challenges.

## Other Approaches

If the three drivers of our energy policy are indeed occurring then somehow investments will have to be made in the system to address them. If the liberalized markets are unable to drive this investment then the utility industry is in need of more change. Other sources of electricity and new technologies will be necessary to have a reliable system in the future. To address the need for clean electricity, new technology such as Carbon Capture and Sequestration (CCS), clean coal methods, and renewable energy sources will all have to be part of the portfolio. Unfortunately there is no historical basis for us being able to find a quick fix. There is no one clear goal to accomplish and there are not seemingly unlimited funds available for another Apollo or Manhattan Project[15]. Unfortunately, as described above, the United States will not be able to make the necessary changes through market-based policies alone. The rural areas did not have access to electricity in the past until the federal and state governments provided incentive for the utilities to do so. Large hydroelectric projects would not have been undertaken by investor-owned utilities. The federal government had to step in with funded initiatives such as the Tennessee Valley Authority or the Hoover Dam. Similarly, the goal of providing cheap, secure, and clean electricity will require a long term plan and some incentive for the utilities to change. If history serves as an example, the changes should include market-based competition, consumer-based demands, and regulatory coaxing to implement policies that truly address our need for cheap, secure, and clean electricity into the future.

One possibility is for the utilities to change how they conduct business. The historical business model of the power utility industry has been that of a single-sided platform with rigid government regulation. Single-sidedness comes from there being a single producer at one end and a buyer at the other[17]. The producer does not buy and the buyer does not sell. To minimize monopolistic issues with this model, a public utility commission or a similar governing body is used to set profitability for the utilities.

There are other methods for addressing the new energy policy goals of the U.S and without ignoring the aging utility infrastructure and the trials of industry de-regulation over the last 20 years[18]. To many in government and the utility industry, de-regulation (more market-based reforms) is still seen as the best method for making progress and fomenting change in the electric utility industry. Still others believe that through the use of known and tested concepts such as feed-in-tariffs, distributed generation, time of use rates, and improved consumption efficiency, the power utility industry could begin to adopt a more diverse, multi-sided platform model[19; 20]. The multi-sidedness comes from all parties connected to the electrical grid being able to participate in buying and selling electricity. Even consumers would be allowed to generate their own electricity and sell excess power to the grid[21]. Could the utilities adopt this multi-sidedness through the use of these concepts? Does this make economic sense for the utilities? This paper will discuss this question.

Regulatory issues are always a part of any utility discussion. If utility companies are to change the way they conduct business, regulatory bodies will have to approve changes in billing practices and rate structures. Public Utility Commissions or Public Service Commissions are usually the government bodies that oversee the near-monopolies of the investor-owned utilities. In a simplified form, if regulatory bodies are functioning properly, they act as a check on the profits of utility companies and protect the consumers' interest in maintaining quality infrastructure. Regulatory bodies, or in the case of this paper, the State Corporation Commission (SCC) of Virginia, review the rates and profits of the utility companies they oversee. If the profits are deemed too high then rates are adjusted downward and if the utilities are not generating the appropriate revenues to pay for their asset bases and operating costs then rates or other adjustments can be made upward.

### The Purpose of this Thesis

This thesis will present a tool that can evaluate the costs and benefits from feed-in-tariffs, distributed generation, time of use rates, and improved efficiency for Harrisonburg Electric Commission. This tool is designed so that it might be used by stakeholders such as utility executives or regulatory bodies to investigate the implementation of combinations of these strategies. Homeowners will also benefit indirectly from this analysis because the model will either validate or disprove the strategies individually and in combination. All of these stakeholders will need to play a part in future changes to the electrical infrastructure so the model must be able to show benefit for all groups to elicit their participation. It is hoped that by combining feed-in-tariffs, distributed generation, time of use rates, and improved efficiency at the consumer level, the utility industry can adjust its profit structure away from the historical one-sided, 'sell as much as you can' model, homeowners can lower their consumption, and the regulatory bodies will be able to explore how to change regulation in order to capture these benefits. The simulation tool is a starting point for this analysis by the stakeholders.

There is a great deal of literature available on the individual concepts[19; 20; 22-24]. There has even been discussion over the last 5-10 years about the systems approach of combining these strategies in a comprehensive strategy[18]. This thesis describes this systems approach and develops a system dynamics model to simulate and demonstrate the interaction among implementations of these concepts and show how utility businesses can help lower the consumption of electricity by their customers and still remain profitable. Although one of the benefits of the actual implementation of these policies is to increase electrical grid resiliency, it is not the goal of this thesis to demonstrate it. The scope is strictly limited to the financial impact of the proposed policies or strategies.

This model could be used to evaluate the economic benefit of businesses, individuals, or other entities producing their own power and selling any excess to the utility. Using these scenarios, the utilities could be in the position of acting as clearing houses for the electricity sales between these producers and consumers (a process known as wheeling) and provide system infrastructure and oversight for the exchange. The utilities could offer the new products and services to the consumer to allow for reduced consumption by giving homeowners better control over consumption. These strategies might lower the utilities' operating costs by slowing new capacity requirements, reducing peak demand loads and their associated costs, and reducing loads on existing transmission and distribution infrastructure thus lowering maintenance costs and providing a more reliable grid . From these changes, it could be possible for the utilities to help reduce consumption but share in the resulting reduced costs[18; 25]. Load swings could be better managed and excess baseload or non-peak capacity can be better utilized during off-peak times[19]. These changes could also lower the growing burden on the aging transmission infrastructure by distributing generation closer to the end user.

This model and paper focuses on one particular region of the United States. The localized boundary condition makes the model easier to implement in regards to annual climate and its direct effect on electricity costs and also the generation capabilities and costs of the electricity distributor. Regulatory issues also affect power distributors on a regional basis.

The region chosen is the service area of the Harrisonburg Electrical Commission (HEC) which is a municipal electric company in Harrisonburg, VA. HEC has limited generating capacity but still has a cost structure with baseload and peak demand components. There are aspects to HEC's business structure that limit the analysis of the combination of the four strategies. These issues are discussed later in this paper.

This model is built to be flexible enough to be adapted to other regions of the country and to other utilities. Through adjusting set-up parameters, most utility business styles can be analyzed. Small municipal distributors, rural cooperatives, and large regional utilities could be simulated using this model.

Only the residential customer class will be accounted for in this model. Commercial and industrial customers have load requirements and pricing factors that differ significantly from residential customers. To limit the complexity of the discussion and model, these two categories will not be included. The choice of residential loads is also based upon the fact that it is currently the largest market sector with over 38% of the total electricity used, continues to grow, and that more work needs to be done in this area compared to the industrial and commercial segments[26]. The model will use data provided by HEC but limited to the segment that relates to the residential customer class.

The regulatory structure has grown immensely complicated over the years with the implementation of fuel cost recovery charges, regional transmission organization charges, and myriad other fees and mechanisms for bringing many stakeholders to the bargaining table during rate cases. Because the purpose of this paper is to investigate new business strategies for a utility, the regulatory structure will be included. However, the effects will be limited to the profit checking efforts and will not include political ramifications of changing the structure of the utility business model. Hence, the case may be made from this paper that utilities will have a profit motive to change the way they conduct business so regulatory enforcement of new government policies might not be necessary.

## Specific Research Questions

The goal of this thesis is to answer the following questions:

1. How might combinations of the strategies of Time of Use pricing, Feed-In-Tariffs, Distributed Generation, and Energy Efficiency affect HEC energy costs, consumer electric bills, and overall electrical consumption in the HEC residential class customer base?

2. Which one of the strategy combinations from question number 1 provides the best outcome for the profitability of the utility?
3. Which one of the strategy combinations from question number 1 provides the best outcome for the saving of the most energy?
4. What changes in the regulatory environment would improve the prospects for adopting these strategies?

## The Four Strategies

### Just Four Policies

The four main policies that this thesis will investigate are related to well known policies that have been implemented in the recent past. Many are still being used in some form today. The four policies include:

1. Distributed Generation (DG)
2. Time of Use (TOU)
3. Feed-in-Tariff (FIT)
4. Energy Efficiency (EE)

To address the energy issues of cheap, secure, and clean energy, there are certainly dozens of policies or strategies that might be used. For many years, the United States and its citizens have debated the need to open more territories to oil, gas, and coal exploration. Nuclear power is still a viable option. It is considered a greenhouse gas (GHG) friendly source of electricity but it is debated whether utilities can afford to implement it under the current regulatory requirements. However, more fossil fuels and nuclear power do not address all three of the energy policy requirements of energy being cheap, secure, and clean. They do represent business as usual in terms of large-scale generation and delaying any significant changes to the policies of the last 70 years.

Other possible strategies look to underdeveloped or untested technologies like clean coal processes, a hydrogen powered devices, or producing cellulosic ethanol. Millions of dollars are still being spent each year on fusion related research. All citizens would like to have the one technology that addresses all of the energy requirements of the nation. Historically, this has not occurred. Civilization knew of and used coal three thousand years ago but it took the confluence of the steam engine, railroads, and the scarcity of wood for Europe to convert to using mostly coal in the 19th century. By 1900, coal still accounted for 93% of the mineral fuels consumed in the U.S. Oil was still being used in its kerosene form but as more oil was discovered and the new demands of the gasoline engine for more oil distillates grew, oil's portion of the total energy consumption crept up[27]. Nuclear power appeared in the mix in the 1950's after it was realized that nuclear fuels were more abundant than previously understood. It has taken decades if not centuries for every major energy source to develop and grow into a useful percentage of energy input. Based upon this history, it is unlikely that a new technology is going to take a primary position in the next 10-20 years. We must consider known and tested sources and implementations that can fulfill the needs of the modern energy policy.

## Distributed Generation

### Definition

Distributed Generation (DG) is a concept that has been used for decades but has not been truly defined or discussed as a potential energy strategy until recently. In most cases, the term ‘distributed generation’ is used in opposition to the large-scale, centralized generating plant that are most common in the industry. However, in Ackermann [28], the term is shown to have different defining qualities. As stated above, some suggest that the capacity of the DG defines it as such. Placement of the DG's interconnection to the grid might also define DG. In the literature, the following characteristics of DG might be used to differentiate it from traditional, centralized power generation.

1. the purpose of the generation;
2. the location of the DG;
3. the rating or capacity of the distributed generation;
4. the power delivery area;
5. the technology used to produce the electricity;
6. the environmental impact of the DG;
7. the mode of operation or how and by whom is the DG is controlled ;

8. the ownership of the generation;
9. the market penetration of distributed generation;

For the purposes of this paper, most of these characteristics are assumed. For example, for the model, the environmental impact of the DG will not be measured. However, from the symbiosis between DG and FIT, the author assumes that the impact will be minimal because it is FIT is usually defined as a renewable source but the model will not take this into account. Corresponding to the list above and for the purposes of this paper, the following assumptions are made:

1. The purpose of the DG is provide additional generating capacity to the grid. It will serve to correct power factor or provide back-up capability.
2. The placement of the DG in the electrical system will be downstream of the distribution transformers and most likely on the customer's side of the meter.
3. The rating or capacity is not important as long as it is known. Most DG is less than 10MW which is much smaller than most utility-owned generation facilities.

4. The delivery area is assumed to be HEC's delivery area.
5. The generating technology is not important other than it must be known so its marginal cost can correctly be used.
6. The environmental impact is not implemented in the model but is assumed to minimal because of the use of renewable energy in most cases.
7. The mode of operation or who will control it will be implicit in the model. The DG will be used when the model calls for it.
8. The ownership is undeclared in the model. The cost of implementation will be included but which stakeholder actually pays the cost is the subject of future work.
9. The market penetration will be modeled in that as penetration grows the beneficial effects will be monitored.

**Distributed Generation: Implementation**

Examples of distributed generation include photovoltaics(PV), wind turbine, and Combined-Heat and Power (CHP) in its micro-turbine format. Typical PV systems on a residential roof might vary between 1 kW and 20 kW. Single wind turbines can range from less than 1 kW up to 7.5 MW found in the latest, largest sizes. Gas turbines are used by utilities today as their newest form of generation. Some versions are used for quick acting generation for peak loads. Recent developments of the shale gas fields throughout the U.S. have considerably lowered the cost of natural gas. This fact has improved the cost benefit of gas-powered turbines and CHP represents the most efficient form because of its heat recovery capability. For the model, CHP microturbines of 65 kW or less are considered to be a possible source of DG capacity. If used in conjunction with secondary heat capture, the thermal efficiency can reach over 80% which is much higher than traditional power plants fired with coal or natural gas[22]. There are other possibilities for DG capacity. Fuel cells, small hydropower, and biomass-fueled generation are all viable sources for distributed generation.

All of the above could be used in quantity to create a large, centralized plant. There are wind farms that can generate tens or even hundreds of MW of electricity. However, what makes these sources unique is their granularity.

Most coal-fired plants, nuclear reactors, or gas turbines are large scale projects that generate large quantities of electricity in one location. The centralized plant requires years of planning, permitting, and construction. A single installation of PV or wind turbine can be designed, permitted, and installed in a few weeks. Instead of one 500MW coal-fired plant, the plant could be replaced with 125,000 installations of PV on residential roof-tops.

Another unique characteristic of DG is the possibility of multiple ownership. Instead of one company owning the electricity generation for thousands of homes and businesses, there could be a combination of ownership across DG resources. Utilities could own and lease DG. Other businesses, small and large, could invest in DG and sell the electricity to the utilities or directly to the consumer through Power Purchase Agreements (PPA). Homeowners could purchase DG systems, have them installed, use the electricity they need and then sell the excess back to the utility. This characteristic enhances energy security.

## Distributed Generation: Pluses and Minuses

One of the largest advantages of DG is that it provides an easy method for renewable energy sources to be installed. The very nature of renewable energy is that while producing electricity, there are no non-renewable energy inputs. Even if these systems are less efficient technically, the lack of wasted fossil fuels is significant. The diagram (***Figure 3***) shown [29] below does not show inefficiencies of individual sources of energy but it does show how much of the Electricity Generation inputs are wasted as rejected energy. The total energy inputs for generation from all sources in the United States in 2009 was estimated to be 38.19 quadrillion btus and the rejected portion was 26.10 quadrillion btus or over 68%. This indicates that our generation system on average has less than 32% thermal efficiency. Production level PV systems currently do not top 20% efficiency of energy output from energy input but because the energy source is sunlight, PV systems do not waste non-renewable sources as do coal or natural gas. Similarly, wind turbines use a renewable energy source input so there is no rejected energy component from wind in the chart below. These sources of DG waste no fossil fuels and produce no green house gases during operation.

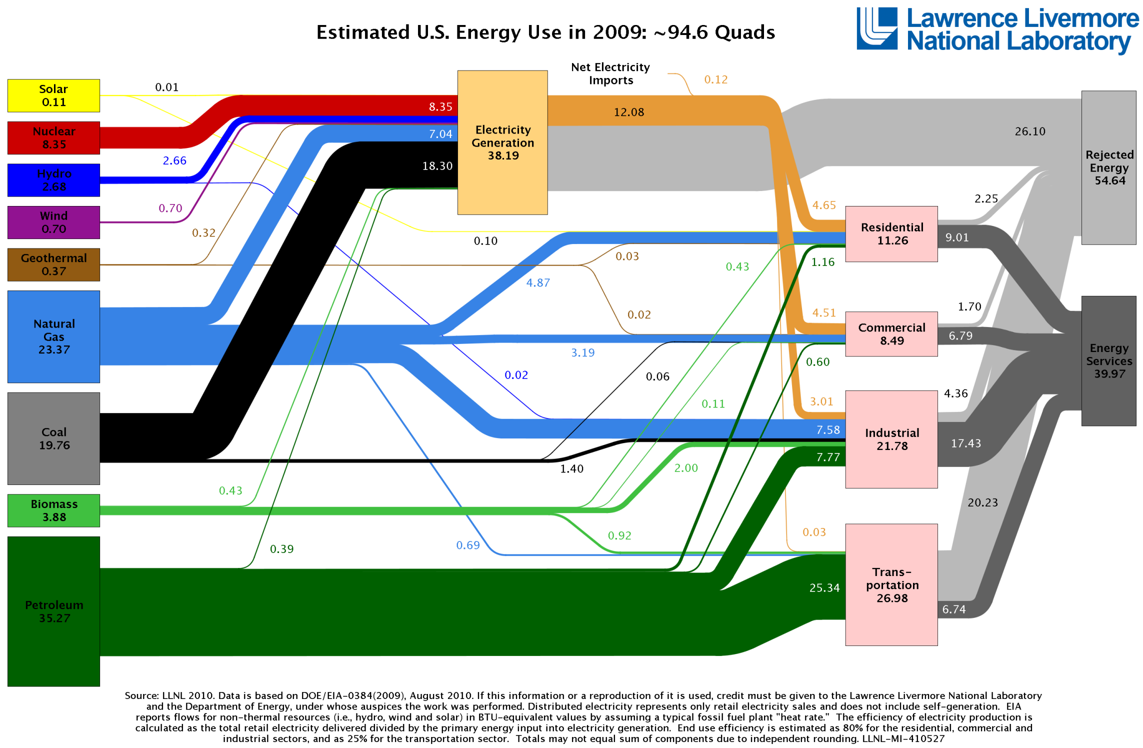


**Figure 3- U.S. Energy Use, Sources and Consumption by Sector**

Another benefit for using DG comes from generating electricity away from the traditional, large-scale, centralized plants. Although this creates a more complex system, it also creates a more resilient system for several reasons. First is the fact that DG allows generating capacity to use multiple fuel sources. By not picking a particular fuel as a source for electrical generation, DG can absorb changes to the supply and prices of these fuels. Second, if a central plant goes offline, this capacity must be replaced within seconds to minimize disruption to the grid. A central plant might generate enough electricity for over 100,000 homes and businesses. If a DG system, such as a photovoltaic array on a homeowner's roof, goes offline, then only that home or group of homes near the DG resource is threatened by disruption. Finally, the required reserve capacity for the central plant is hundreds or thousands of times larger than when using DG[18] As the number of segments of a generating system increases, the risk of losing a certain percentage of capacity at any one time decreases[30].

For the utilities that have to build new capacity in the future, there are economic benefits to DG. The centralized plant takes longer to produce revenue than for DG of the same capacity. The central plant requires investment further in advance of the plant actually producing power. That same gain in capacity through DG will result in a return of capital sooner because portions of the capacity will be completed and come online earlier. This idea is illustrated in ***Figure 4*** below. This benefit can negate the current

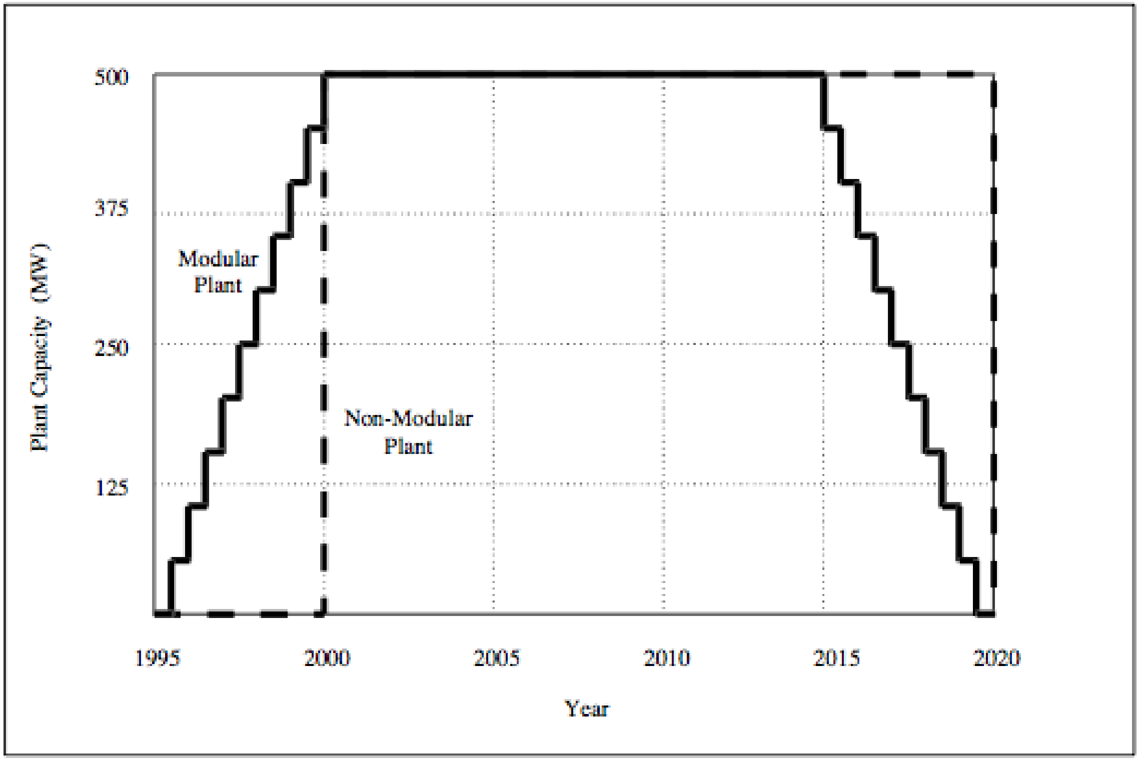


***Figure 4 - Use of Capital for Centralized Generation vs Distributed Generation*** *[30] The 'Modular Plant' represents distributed generation and the 'Non-Modular Plant' represents the larger, centralized plant.*

differences in the marginal cost of renewable sources and coal or gas-fired plants. Also, because the extended timeline for the construction of a large plant, the utility must plan for high enough capacity to allow for demand growth before the next large plant is built. This results in periods of idle capacity and periods of overcapacity which cost money. This difference is shown in ***Figure 5*** below. This figure shows the difference between the addition of central sources of generation and where on the same timeline, DG might be installed to achieve the same capacity.

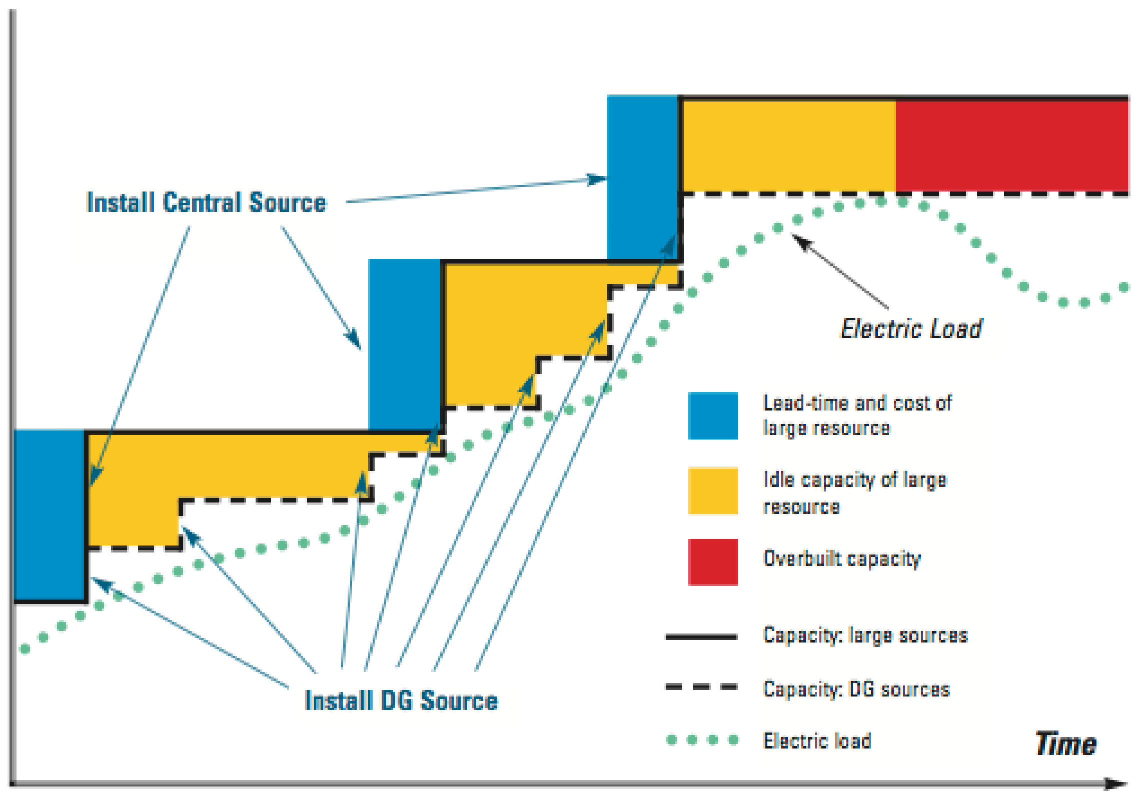


**Figure 5- Capacity Margin Effects for Distributed Generation vs Central Source [31]**

The last economic listed here relates to the investment risk of central plants. **Figure 5** shows the market dynamic of installing capacity in chunks. The planning and forecasting for new capacity requires some idea of what the electrical demand will be in the future. As that forecast becomes further and further into the future, the risk associated with the investment grows. In the past, utilities have had to raise large sums of money through corporate bonds in order to build new plants. The market judges the viability of the project and the associated risk for the utility by assigning an interest rate to the bond. As risk goes up so does the cost of the bond because potential investors demand a higher return on their money. If the same capacity were installed in steps then not only would each investment be smaller than the large plant but its risk would be judged separately. The risk should be smaller because the forecasting time window is shorter. Therefore, the interest rates should be lower along with the cost to the utility.

There is an inherent efficiency by using DG instead of central plants. Because DG is closer to the actual point of consumption there are less losses due to transmission and distribution (T&D) distances which are generally between 6% and 7% of the total energy. If the DG is located on the customer side of the meter, there are essentially no T&D losses. Most forms of DG also have the ability to correct for power factor issues. A perfect power factor is 1 and occurs when the phase of the AC current waveform and the phase of the AC voltage waveform in a power transmission are aligned. Power factor is the ratio of real power to the apparent power of the circuit. Real power is the instantaneous power delivered while accounting for the phase difference. Apparent power is the same current and voltage but at no phase difference. Power factor can become less than one when inductive loads such as motors or capacitive loads such as switching power supplies affect the power in the circuit. Power factor becomes a problem for two reasons. The first reason is that the grid must be sized for apparent power. If power factor becomes less than one then the real power delivered becomes less than the apparent power so the system must be oversized to accept this difference. The second reason is that consumers pay for real power used but the utilities must generate the apparent power. If power factor is significantly less than 1 then the utility must absorb the lost revenue.

DG allows for new technologies to be implemented in small quantities which is the normal growth path of new ideas. DG does not pick a winning technology like government subsidies or tax credits. It merely makes best use of it and allows the success or failure to be determined by the market.

There are two areas of concern for distributed generation. Both are propagated by the utility industry but these two areas need to be addressed for successful DG implementation. The first is the fact DG will require the utility to either give up control over some of its capacity or find a way to install and maintain thousands of DG sources throughout their service area. Giving up control means reducing their sales and perhaps their profits. Installing and maintaining the DG sources would require the utilities to change the way they staff their companies. The expertise required to keep the DG operational will be specialized and most likely be a larger and more diverse group than utilities currently employ. This new requirement would be a fundamental change to the business model of the utilities of today especially in an industry that is faced with the fact that 500,000 energy industry workers will retire over the next five to ten years. In 2006 Department of Energy report titled "Workforce Trends in the Electric Utility Industry"[32] page 6, the DOE writes:

*From the early 1990s into the early 2000s, electric power utilities experienced a general steady and overall decline in workforce levels. That trend may have been largely due to restructuring of the industry, which began in the early 1990s. The introduction of deregulation created a competitive utility market prompting electric utilities to downsize in an effort to reduce operating costs.*

Since 2000, the DOE found that[32] page 7:

*The electric utility industry`'s employment level for lineworkers has been steadily increasing. This hiring trend is driven by utilities`' anticipation of increased demand, and is a response to the long periods of little or no capital investment. Utilities, concerned with the prospect of meeting the rising demand for energy using the existing transmission lines, embarked upon a hiring trend focused on employment to maintain, upgrade, and expand the electric utility system.*

How can the utility industry deal with the necessary changes to begin implementing DG if it already has future employment issues? Perhaps this can become an opportunity for the utilities to remake themselves for this new paradigm.

The second issue is the problem of 'power islanding'. When the grid goes offline due to storm damage or equipment failure then the distributed generation must disconnect from the grid and then reconnect in a synchronized way when the grid is restored. The purpose for the disconnect is to protect the lineworkers from rogue power sources while working to repair the damage. This problem is well known and is being addressed by new standards that equipment manufacturers and installers will have to follow. Although this is a relatively new problem for the U.S., there are thousands of DG installations throughout the world that have addressed the concern.

These two concerns add to the requirements in order to successfully implement distributed generation but are not insurmountable. If the utilities have a profit motive to implement DG then many of the other hurdles will be overcome. Hence, the model presented provides some basis for evaluating if such benefits to the utilities are possible.

**Distributed Generation and Harrisonburg Electric**

Currently, HEC can only gain slight benefit from its own generation capacity. Under its contract with Dominion, there is a penalty for using HEC's generators to reduce its peak load unless it can use it every day. Dominion charges a Coincident Peak (CP) Demand charge based upon HEC's demand in kilowatts during the hour of the month that Dominion is producing its greatest amount. For example, if Dominion's biggest hour during the month of January is on January 3rd at 8:00AM, then HEC pays a demand charge based upon what it was drawing during that hour. In most cases, this charge is as much as 50% of HEC's total electricity costs. If HEC tries to mitigate that Peak Demand by running some of its expensive generation and actually lowers the CP too much then HEC will have to pay a penalty to Dominion in the amount of the difference between Dominion's CP hour and HEC's actual peak load during the month.

If HEC could implement DG that provides some peak shaving capability, then DG would have a direct benefit to HEC's profit for the month. However, due to the contract requirements, HEC would have to use the DG in the same way every day. It could not simply predict the Peak Demand hour and use the DG during that hour. The DG would have to be implemented so as to reduce the peak load every day for HEC.

HEC enjoys a well-designed distribution system with plenty of capacity. The benefit from DG that lowers the loads on distribution systems would not be enjoyed by HEC in the near future.

## Time of Use

### Definition

Time of Use (TOU) is a term that is applied to electricity rates that vary based upon the time of day and season of the year. The original purpose for TOU was to allow the utility to charge more for periods of time when demand was at a peak. Most utilities have different types of generation that are categorized by how quickly they can respond to changes in their loads. The cheapest to operate are the 'baseload' generators that do not respond quickly to load changes. The most expensive type are the 'peak load' generators that can respond to load changes within minutes. The utility keeps the baseload as steady as possible and then fills in the load demand with peak generators. The TOU rate allows the utilities to recover these higher costs more evenly and predictably. Traditionally, this rate structure was used with industrial customers and some commercial customers because their loads were large and exhibited high peak loads. Since the 1980's, the TOU rate has been made available to the residential customer class as well. This rate structure differs from what most residential customers currently use. The standard, single rate means that the customer pays one price for all electricity independent from the time of day or the season of the year. The standard rate is safe for the customer but a risk for the utility.

The idea behind TOU is to match the rate for the residential customer to the actual generating costs of the utility. Regulators allowed TOU with the goal of lowering overall costs to the customer and giving the utilities a more predictable profit. As with the industrial and commercial classes, the TOU rate will be highest during the peak demand times such as a hot summer afternoon and will be lowest during the period of lowest demand such as between 12:00am and 7:00am during most of the year. By implementing the TOU rate structure, the hope is to provide incentive for the consumer to shift load demand to the off-peak times. This policy could also help reduce the peak demands for some utilities and allow them to lower costs. This policy could also help the utility make better use of their baseload capacity which is usually idled to some degree during off-peak times lowering generating efficiencies.

## Time of Use: Implementation

***Figure 6*** below shows how the residential TOU rates work at Alabama Power. During the Winter Peak Hours, the rate is $0.07 per kWh. During Summer Peak Hours, the rate is $0.25 per kWh. All other times have a rate of $0.05. This rate structure is compared to the utility's standard ‘FD’ rate which is $0.078 per kWh for every hour of the year and only changes when the customer has reached a certain threshold for the month[33; 34]. In the summer, the rate increases slightly above 1000 kWh of consumption and in the winter the rate decreases slightly above a monthly consumption of 750 kWh.

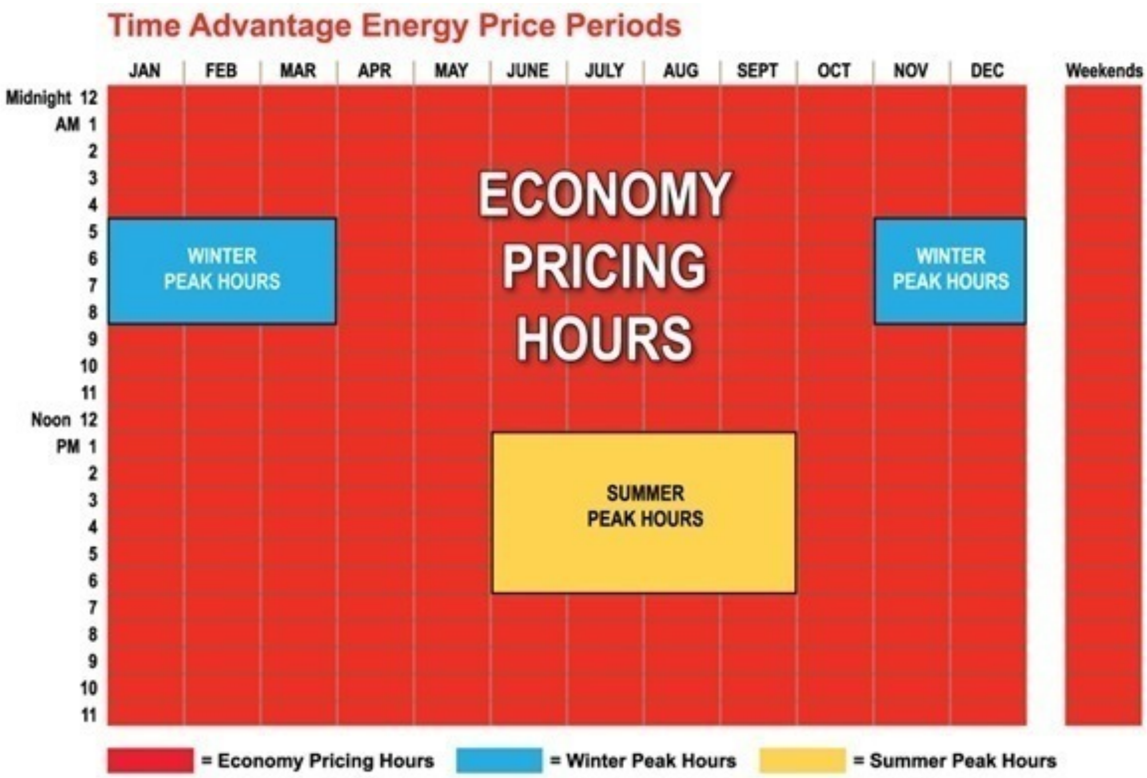


**Figure 6 - TOU Hours** *This diagram show the times of day and months of the year where peak pricing is used in Alabama Power's Time Advantage (a.k.a. TOU) rate offering* [35].

Similarly, Dominion Corporation's Virginia Power offers residential TOU rates but with a different time and cost structure. Virginia Power's peak hours are from 11:00am until 10:00pm during the summer and the peak rate is $0.1498 per kWh and off-peak rate is $0.0249 [36; 37]. For Virginia Power there are no shoulder or mild-season months as shown in ***Figure 6*** for Alabama Power.

Hydro One Networks Inc. is Ontario, Canada's largest utility. They offer residential TOU rates and have produced a study as to the efficacy of the plan. The report is based on a pilot study with 500 customers with services of less than 50 kW. The goal was three-fold. First was to assess the technical requirements to implement the TOU rates which include new communication infrastructure between the utility and the customer. Second was to measure the impact of an in-home, real-time monitoring device that allowed the homeowner to know current power consumption and keep track of the current power rate. The third goal was to measure the change in behavior of the customers using the TOU rate structure [19].

Some of the general findings were:

- The typical customer on TOU rates, the load-shifting impact averaged 3.7% during peak hours in the summer months and the conservation impact averaged 3.3%. The conservation impact is the total reduction of energy consumption during all times.
- Providing the real-time monitoring to customers on TOU rates helped them respond even more. On a normal summer

day, the load-shifting impact averaged 5.5%, while the conservation impact averaged 7.6%. On a hot summer day (over 30°C), the load-shifting impact was even more pronounced at 8.5%.

- 76% of pilot participants under the TOU rates paid a lower electricity bill as a result of load-shifting, compared to the regular rates. Savings attributable to conservation were incremental. Customers who were better off gained on average about $23 during the pilot (about $6 per month), while customers who were worse off on average lost about $7 (less than $2 per month). (Note: The TOU rates used in the pilot study in Ontario had peak rates of only $0.097 per kWh vs the Alabama Power rate of $0.25 and Virginia Power peak rate of almost $0.15 per kWh. These higher rates might have caused a different impact.)
- 72% of participants indicated that they would like to remain on the TOU rates, and 87% claimed they changed their behavior during the pilot. Only 4% found the changes in their daily activities in response to the TOU rates to be inconvenient.
- 63% of participants with a real-time monitor found it useful to help them conserve electricity. On average, custom-

ers thought they would save 9% on electricity consumption by using them.

### Time of Use: Pluses and Minuses

A major drawback of the TOU rate is the difficulty in implementing the rate for a homeowner because he rarely has the ability to shift significant portions of his load without modifications to his systems. Other than running appliances at night or setting thermostats to a lower temperature during peak summer hours, the homeowner has very little ability to shift his electric load away from the peak times. This drawback has caused many utilities to remove the TOU rate from their offerings. Many of the TOU rates that were offered after the Public Utility Regulatory Policies Act (PURPA) was enacted have either been greatly changed or phased out completely since the 1980's.

The rate plans discussed above and many others like them have been offered as a choice to the residential customer for many years. The complexity of the TOU rate structure and the lack of ability to actually monitor consumption makes uninformed consumers frustrated because they are more likely to see their power bills increase rather than decrease under TOU. As Frank suggests in the Hydro One report, having a real-time monitoring device can help mitigate some of that increase [19].

In all cases, the goal of the utility is to promote peak load shifting through economic incentive/ penalty mechanisms. The difficulty in taking advantage of the incentive means that this strategy must carefully be implemented. However, as Frank indicates, there can be benefit to the utility as well as some return to the customer in well-implemented cases.

There are several benefits from the use of TOU rates that have been mentioned. Lowering the utility's costs by reducing the amount of peak capacity generation can be significant. If using TOU can pass some of those savings to the customer then both parties might share in the benefit of using more baseload capacity and less peak generation.

A white paper produced by Colorado Springs Utilities dicusses these benefits[38]. The paper uses the term of 'load factor' to measure what percentage of installed capacity is being used at any particular time. A low load factor means that a small percentage of the potential capacity is being used to generate electricity. A load factor of 1.0 means that all capacity is being used. Because utilities have to plan for that small percentage chance of a 1.0 load factor, the total capacity must always be available or risk brown-outs or blackouts for their customers. This excess capacity adds expense to the utilities which must eventually be passed to the customer. Therefore, a low load factor causes the average price of electricity to be higher than the actual generating costs because a greater portion of the cost is coming from the costs associated with the standby capacity. The goal of the utilities should be to get as close to 1.0 as possible which supposes that the daily demand curves are level and the utilities can take full advantage of their installed capacity. If TOU helps to remove the peaks, then the demand for the utility will be more level thus raising the load factor and lowering its costs.

### Time of Use and Harrisonburg Electric

Because HEC buys most of its power from a regional producer, a large component of its electricity cost is a peak demand charge. The peak demand charge is based upon HEC's demand during the hour of the month that its supplier encounters its greatest load. This hour might not coincide with HEC's peak demand hour. The hour that the charge is based upon is referred to as the Coincident Peak or CP. HEC's true demand peak would then be referred to as its Non-Coincident Peak or NCP. Data provided by HEC has shown that the CP and NCP are usually on the same day but might differ by several hours. The charge is calculated as HEC's CP demand in kilowatts multiplied by the suppliers Demand Charge rate. For the purposes of this paper, the current rate of $16.607 per kW will be used. The CP ranges from 95 kW to a high of 133.4 kW throughout the year.

This cost structure for HEC means that reducing the CP demand would be beneficial for HEC by reducing their costs and thus increasing their profit. The TOU portion of the model explores this impact on HEC’s profit, to the customer's power bill, and overall consumption using three scenarios. The first scenario is implementing peak load shifting with no rate change for the customer. Second is to implement peak load shifting with the TOU rates implemented. Lastly, the model shows the impact from implementing just the TOU rates with no load shifting.

## Feed-in-tariffs

### Definition

"A feed-in tariff (FIT) is an energy-supply policy focused on supporting the development of new renewable power generation. In the United States, FIT policies may require utilities to purchase either electricity, or both electricity and the renewable energy (RE) attributes from eligible renewable energy generators."(page 2)[20] This FIT contract provides a guaranteed payment for the full output of the system for a guaranteed period of time.

The idea of the FIT is to promote Distributed Generation (DG) growth and to improve market economies of scale thus promoting a more sustainable, renewable energy source. A FIT is a more formalized version of net metering. Under a net metering arrangement, the utility company buys any excess generating capacity provided by a customer. An example would be when a homeowner, using photovoltaics (PV)on his roof, actually generated more electricity than was being consumed. This excess would then be sold back to the utility at some variable cost that the utility generally determines. In a net metering application, the price paid by the utility is generally not high enough to justify the initial investment in the PV system. Net metering became common when the Public Utility Regulatory Policy Act (PURPA) was passed in 1978. PURPA required utilities to pay for electricity produced by certain Qualifying Facilities if the cost was less than their existing avoided cost. The avoided cost for a utility is the marginal cost of the electricity generation that would be 'avoided' if the electricity was purchased from another producer. Qualifying Facilities were generally large producers of electricity. In an attempt to acknowledge smaller renewable energy sources such as a homeowner with PV on the roof, utilities began net metering programs.

FIT is different from net metering in that it contractually sets the price that the utility will be required to pay for a set time period. This time period is usually dozens of years and is generally long enough for the homeowner or any other independent producer to recover the capital costs of the generating equipment. The contract is enforced through legislation or public regulatory policy that sets the requirements and standards for the FIT. Although there are several common methods for setting the FIT price, more successful FITs determine the price by calculating the levelized cost of the particular source which takes into account the actual generating costs of the equipment including purchase, installation, and operation and maintenance. A more formal definition of levelized cost by the U.S. Energy Information Administration is "Levelized cost represents the present value of the total cost of building and operating a generating plant over an assumed financial life and duty cycle, converted to equal annual payments and expressed in terms of real dollars to remove the impact of inflation. Levelized cost reflects overnight capital cost, fuel cost, fixed and variable O&M cost, financing costs, and an assumed utilization rate for each plant type" (page 1)[39]. By using the levelized cost, more incentive is provided to invest in these systems. The cited Energy Information Administration (EIA) report provides examples of common energy sources and the associated levelized cost shown in the table below.

| Plant Type | Capacity Factor (%) | U.S. Average Levelized Costs (2009 $/megawatthour) for Plants Entering Service in 2016 | | | | |
|---|---|---|---|---|---|---|
| | | Levelized Capital Cost | Fixed O&M | Variable O&M (including fuel) | Transmission Investment | Total System Levelized Cost |
| Conventional Coal | 85 | 65.3 | 3.9 | 24.3 | 1.2 | 94.8 |
| Advanced Coal | 85 | 74.6 | 7.9 | 25.7 | 1.2 | 109.4 |
| Advanced Coal with CCS | 85 | 92.7 | 9.2 | 33.1 | 1.2 | 136.2 |
| Natural Gas-fired | | | | | | |
| Conventional Combined Cycle | 87 | 17.5 | 1.9 | 45.6 | 1.2 | 66.1 |
| Advanced Combined Cycle | 87 | 17.9 | 1.9 | 42.1 | 1.2 | 63.1 |
| Advanced CC with CCS | 87 | 34.6 | 3.9 | 49.6 | 1.2 | 89.3 |
| Conventional Combustion Turbine | 30 | 45.8 | 3.7 | 71.5 | 3.5 | 124.5 |
| Advanced Combustion Turbine | 30 | 31.6 | 5.5 | 62.9 | 3.5 | 103.5 |
| Advanced Nuclear | 90 | 90.1 | 11.1 | 11.7 | 1.0 | 113.9 |
| Wind | 34 | 83.9 | 9.6 | 0.0 | 3.5 | 97.0 |
| Wind – Offshore | 34 | 209.3 | 28.1 | 0.0 | 5.9 | 243.2 |
| Solar PV[1] | 25 | 194.6 | 12.1 | 0.0 | 4.0 | 210.7 |
| Solar Thermal | 18 | 259.4 | 46.6 | 0.0 | 5.8 | 311.8 |
| Geothermal | 92 | 79.3 | 11.9 | 9.5 | 1.0 | 101.7 |
| Biomass | 83 | 55.3 | 13.7 | 42.3 | 1.3 | 112.5 |
| Hydro | 52 | 74.5 | 3.8 | 6.3 | 1.9 | 86.4 |
| | | | | | | |

**Figure 7- Levelized Generation Costs of Different Fuel Sources** *Note that natural gas currently has a price advantage over most other sources which might explain that most new generation is some form of natural gas-fired turbine. Surprisingly, on-shore wind is competitive with conventional and advanced coal. In this chart 'CCS' refers to carbon capture and sequestration*[39].

The three most common pricing schemes for FITs are:

1. A fixed price for each kilowatt-hour over the projected life of the system
2. A fixed premium over the normal cost of electricity that might fluctuate over time

3. A price equal to the normal cost of electricity with a guaranteed minimum price

In scheme number 1, the price for the FIT payment remains stable over time which creates stable investment conditions and can provide a lower risk financing environment. In scheme number 2, the fixed premium is intended to promote investment by making the FIT price always higher than traditional sources for electricity. This option would be good if prices remained very stable. Unfortunately, the normal price might drop below that needed to recover investment cost or might rise too high and provide the producer with an unwarranted windfall. These possible fluctuations create a riskier investment environment so the premium must be priced accordingly. Scheme 3 attempts to limit both the upside and the downside of number 2 by placing a minimum price on the FIT but not allowing the windfall if the spot market price fluctuates too high. This plan has been used successfully in both the Netherlands and Spain. One of the drawbacks to scheme 3 is that it requires total transparency of the spot market pricing system. In de-regulated markets that is usually the case but this is not so throughout the United States. Another drawback is that the payment system is much more complex than the fixed payments for #1 and 2. Scheme 3 requires a payment for normal price plus a calculation relating to whether the FIT minimum gets paid. This requires hourly tracking of prices and production and requires a very complicated accounting system to implement[20].

### Feed-in Tariffs: Implementation

A FIT can be applied to non-utility producers both large and small. Many FITs use different pricing for not just the type of system (the source of the electricity) but also the size of the system, acknowledging that the ultimate purpose of a FIT is increase the benefits from scale. Normally large systems are paid a lower price than the smaller scaled projects(generally < 25kW)[10].

The Feed-in-Tariff has a documented history that extends back to 1978 and the passage of the Public Utility Regulatory Policies Act. Another outcome of PURPA was the use of Power Purchase Agreements (PPAs). The PPA is essentially a FIT that is granted on a per case basis. A PPA is a contract that is negotiated between a non-utility power producer and some buyer. The buyer might be a utility or the end user of the power. The problem with PPAs is that they must be negotiated one contract at a time and have no set standards or stipulations. FITs have these stipulations and design options built into the legislation.

Portugal implemented a nationwide FIT in 1988 and Denmark, Germany, and Spain instituted FITs in 1990, 1992, and 1994 respectively. Now there are successfully implemented FITs in over 30 other countries[10]. Closer to home, FITs has also been implemented in Gainesville, FL and in Ontario, Canada. The program in Gainesville was started in March 2009 and in its first 2 years, connected over 6MW of new PV and has sold out its subscription limits for 2011 and 2012[40]. The Gainesville plan has been so successful in lowering the levelized costs of PV that the price offered in 2009 for small systems of less than 10 kW was $0.32 per kWh has been reduced $0.24 per kWh in 2012 contracts. Ontario, Canada launched its first FIT in 2006. After some problems with implementation and confusion from policy makers, a new FIT was implemented in 2009. Ontario's FIT has induced over 15,000 MW of potential supply and is believed to be creating over 90,000 new jobs per year[10]. Several states have passed legislation with forms of FITs but progress on actual FITs (long-term, guaranteed price) has been made in Vermont, Minnesota, Washington, and Arkansas.

Some FITs have not been successful. Argentina implemented a FIT in 2006 that created a tariff level that was too low to induce investment. Thus it has not reached its proposed goal. South Korea passed FIT legislation that it is now phasing out because of its expense. They had based the FIT on a tax not related to energy and therefore during economic downturns, had overburdened the tax payer[10].

This well-documented history provides many examples of how to and not to implement FITs.

### Feed-in Tariffs: Pluses and Minuses

There are several perceived disadvantages to the Feed-in tariff. The first is that the FIT is not a market-based pricing structure because of its nature of being long-term and fixed price. Miguel Mendonca, the author of *Powering the Green Economy-The Feed-in Tariff Handbook* claims that most of these complaints come from the utilities because a FIT will impose additional requirements on their business as usual practices. Mendonca points out that while it is true that FITs are not a market based pricing scheme, every energy system in use today has required government intervention to overcome market barriers and challenges. The s-shaped growth curve of normal markets does not move fast enough to enable renewables to survive. This same problem has been exemplified in the rural electrification of the United States, the building of nuclear power plants, and even the market growth of the fluorescent light bulbs. Mendonca suggests that the utility companies will need to find a way to co-exist with FITs. The existing market structure with monopolistic utilities has essentially locked out renewable energy with on-going subsidies to fossil fuels such as exploration credits, resource depletion allowances and subsidies to clean up their messes. It is difficult to make small additions to the generation capacity because of past restrictions utilities have had on the grid. Lastly, the lack of external costs being included in the cost of our traditional power sources keeps the true costs of coal, gas, and oil artificially low. Because renewables still produce the same basic product as a coal-fired plant, renewables must compete on price- not the improved features provided by other new technologies[41].

Another disadvantage is that a FIT is designed to embrace new technology on a broad scale. This requires many installations and there might be problems with adding so many interconnections to the power grid. While this is a challenge, it is not a new challenge. Germany has integrated over 350,000 PV installations into its grid and 90% are small-capacity, home-based [10]. The Department of Energy through its national laboratories, trade groups such as the Institute for Electrical and Electronic Engineers (IEEE), and even utility-sponsored organizations are aware of these issues and have interconnection standards in place and are updating them as necessary. Examples would be the IEEE 1547 and UL 1741 which address interconnection of distributed generation to the grid, the safety issues, and the equipment requirements.

A perceived disadvantage of a FIT is that it generally involves renewable energy (RE) sources. The basic nature of two of the biggest RE sources, PV and wind turbine, is that they are intermittent. They do not operate 24 hours per day, 7 days per week as is the perception of coal-fired generators. What most people don't realize is that even coal-fired plants are only operating 87.5% of the time on average. This requires the utility to have at least 15% of reserve capacity at all times and even more to account for unpredictable system failures such as transformer outages. RE is added in smaller chunks so intermittency and failures have smaller effect. RE has generally less downtime and because it is supplied as DG in most cases, it is not affected by transformer failures or even need to use the transmission and distribution system in most cases. Also, there are many ways to store the intermittent power from RE. Pumped water storage has been used in many places around the country for decades to store excess power produced during off-peak times. Other systems use compressed air in underground cavities or even new battery storage systems are beginning to be installed on a larger scale than once realized[10]. These storage systems will become more viable as RE capacity increases and the prices for the power they produce come down.

The disadvantages of FITs have been discussed but what of the advantages? If the U.S. energy policy addresses cleanness and security issues, then FIT can help address both. As mentioned before, FITs involve growing the RE market and the respective generating capacity. Because this RE is DG in most cases, then by its nature RE is more secure. Former CIA Director James Woolsey argues for FITs because they promote DG and DG is a more resilient (secure) system[10] No one system failure in a DG system can remove power from millions of homes and offices like occurred in the black-outs of 1965 and 2003.

Concerning the cleanness issue, there is little debate that RE is a cleaner source of electricity as far as greenhouse gases emissions are concerned. PV and wind turbines will never emit GHG while producing electricity. These technologies have no continual use of water and produce no ash, mercury, or any other pollutants while in production[10].

FITs have been shown to drive down production and installation costs of their components which makes RE more competitive each year. FITs can promote a diversified portfolio of technologies because the prices are based upon levelized costs given that no one technology is picked as the winner in a properly designed FIT. FITs have been shown to produce jobs. FITs promote investment by reducing risk in cost recovery and removing the 'used and useful' regulatory requirement because the FIT is legislated and pre-negotiated and therefore outside of further regulatory review.

The final advantage FITs is that they can enable achievement of Renewable Portfolio Standards (RPS) that have been enacted by well over half of the states in the U.S. RPS legislation generally sets goals for Investor-Owned Utilities (IOU) for purchasing electricity from RE sources. While many states have passed the law, some are struggling with meeting their goals due to lackluster investment. Because RPSs tend to promote low cost implementations of RE, they tend to discourage diversification in RE portfolios. Most RPS projects tend to be large in scale so favor large companies and small businesses or homeowners cannot compete. The demand for capacity is stable but because the price is not guaranteed, the investment contains higher risk. FITs can address all of these problems[20].

In summary, Feed-in Tariffs can have numerous benefits. The FIT legislation must be designed properly but once implemented, it has an impressive track record in promoting renewable energy and the benefits that come with it.

### Feed-in Tariffs and Harrisonburg Electric

If the primary goal of Feed-in tariffs is to promote the growth of DG and more precisely, renewable DG, then there is certainly long term benefit to HEC for implementing FITs. If a FIT is properly instituted, there will be no un-recoverable cost to HEC. The increased cost of electricity due to the FIT will be paid by all customers over the life of the program. The benefits to HEC would include the increased Distributed Generation in its system, the ability of PV to lower peak demand in the summer months, and the goodwill that FITs can generate by promoting renewable energy production. There will not be other any cost benefit to HEC at this time. Because their system has excess distribution capacity and is not currently near equipment limits, the increased DG in HEC's system would not benefit their system or produce savings from limiting the need to expand capacity.

### Energy Efficiency

### Definition

The term energy efficiency (EE) can be used as an economic term that represents how the cost of energy changes over time as it used to generate an economic output. This type of EE can be driven by lower cost energy inputs as well as a lower ratio of energy input to energy output. An example would be the cost of coal over the last 130 years as an input into the production of electricity. From 1880 to 1960, the thermal efficiency of using coal improved by more than a factor of 10 meaning that 10 times more electricity could be produced from the same amount of coal [42]. This gain in efficiency had the effect in the past of making electricity marginal costs cheaper because less coal was necessary to produce equal outputs of electricity even while accounting for slight increases in the cost of coal. However, in this paper, the energy efficiency strategy also refers to a method of reducing overall consumption of energy in the form of electricity. A definition provided by the American Council for Energy Efficiency is: ' The cost-effective investment in the energy we don't use to produce our nation's goods and services '[43]. Amory Lovins calls it 'Negawatts'. A simpler form might be paying more money now for a product that will use less energy and thus cost less to operate over the life of the product. The model evaluates EE using this definition as it relates to the residential customer. While the model will show some of the economic benefits from the EE, reducing the actual amounts of electricity consumption are the primary focus of the EE strategy in this paper.

This reduction in consumption might occur in two ways. One is through lifestyle changes of the consumer. The second is by implementing new, more efficient equipment in the home. Another description of these two concepts is the idea of saving electricity by doing something differently versus doing the same thing with less energy. The lifestyle changes could also be called energy 'conservation' since it refers to behavioral changes that help an individual to consume less electricity. Examples of these changes to behavior would be turning off lights when the homeowner leaves a room or setting back the thermostat when he goes to work. Implementing new equipment would require a homeowner to make the decision to purchase and install a new appliance or water heater that is more efficient than the one currently in use. This action usually occurs at the end of the service life of the existing appliance, would require capital expenditure and is very seldom done inside the life expectancy of the appliance. Examples might be a refrigerator with an EnergyStar rating or a geothermal heat pump that is more efficient than a traditional air-to-air heat pump.

Energy efficiency is important because it represents a way of addressing the energy policy issues without building new electricity capacity. From 1996 to 2006, electricity demand in the U.S. grew 1.7% per year. The Energy Information Administration projects the growth to be 1.07% each year until 2030 which represents a total increase of 26%. Even though historical trends indicate a much higher growth rate, the EIA projections take some EE into account as a result of newer building codes and some market-driven efficiency improvements. There have been several papers written that project the EE potential during this time period. The EPRI report [44] estimates that this EIA annual growth could be reduced by one-fifth to 0.83% per year through EE practices. In terms of total electricity the reduction in growth would represent an annual savings of approximately 11 terawatt hours with a combined total of 236 terawatt hours or 236,000,000 megawatt hours by the year 2030. This represents the average output of more than 7 average sized, coal-fired generating plants over the same time span[2].

The EPRI study breaks the potential gains from EE into three possible scenarios:

1. Technical potential- Includes all households and businesses adopting potential EE practices regardless of cost
2. Economic potential - Includes all households and businesses adopting potential EE practices based upon economic cost-effectiveness of the individual practice
3. Achievable potential- Includes all households and businesses adopting potential EE practices based a more practical standard and falls into two sub-categories:

    a. Maximum Achievable Potential (MAP)- account for markets, societal barriers, attitudes

    b. Realistic Achievable Potential (RAP)- starts with MAP and accounts for financial, regulatory, and political barriers

The estimate of combined annual savings of 236 terawatt hours (5% of the total year-end consumption) provided above represents the RAP scenario. In comparison, the EPRI study suggests that the MAP scenario would increase the savings further to a combined savings of 382 terawatt hours by the year 2030.

There are other reports that have assessed the potential energy savings through energy efficiency programs. A McKinsey report takes a more aggressive approach to EE and shows a potential reduction in residential loads of over 6000 trillion BTU's of primary energy inputs, 4000 trillion of which are electricity. This total corresponds to 1172 TWh of power generation through the year 2020. This reduction comes from a mix of 129 million homes and 2.5 billion electronic devices [45]. The most notable difference in the present research is the use of primary energy inputs instead of end use measurement. Because of energy losses in converting fuels to electricity, transmission losses, and end use equipment losses, the 1172 TWh only represents about 615 TWh of improvement for the homeowner at their meter. The study also discusses investment payback for EE. By assigning costs to the potential strategies and comparing the savings from the electricity savings, Granade suggests that the total projected investment required would only represent half of total energy savings through 2020. However, this investment challenge represents a tenfold increase in investment amounts in EE.

A paper from the School of Public Policy at Georgia Institute of Technology summarizes a number of national and regional studies to show that the projected path of this nation's energy consumption is a sobering view of unsustainable practices [46]. Chandler also uses the summaries to exemplify possible paths of an EE strategy and its large number of benefits. These benefits include GHG reduction, fewer new generating plants, and lowered consumption of energy inputs in the United States. Another report by the trade group, American Public Power Association, discusses how investor-owned utilities (IOU's) can or should recover lost revenue from the effects of energy efficiency programs. IOU's have already installed capacity to handle certain electric loads. If the load is diminished through EE, then the costs associated with the installed capacity become stranded or unrecovered without special rate treatment to deal with the losses. This problem for IOU's makes EE a modern issue for regulators [47].

It is clear that much can be done to implement a EE strategy which would provide at least partial fulfillment of the cheap, secure, and clean requirements for our energy policy.

**Energy Efficiency: Implementation**

The literature provides guidance on how EE might be implemented. According to the EPRI study, large potential residential opportunities[48] under the RAP scenario are:

1. installing and using a programmable thermostat
2. more efficient central air conditioning
3. repair of leaking duct work in residential systems.

Studies have shown that by repairing the duct work in all residential central air conditioning could generate a reduction of 1 Terawatt hours by the year 2030. Using a programmable thermostat under the RAP scenario could generate reductions of over 10 TWh. Other potential opportunities are weatherization, new water heaters, and the use of in-home energy displays to prompt consumer behavior to conserve.

One aspect of EE strategies that is often overlooked is the effect of compounding. By applying EE strategies in aggregate, the energy use reductions can be compounded. For example, if a homeowner installs new, insulated windows and new lighting and a more efficient air conditioner here are the reductions:

1. Windows allow less heat in the house so shades don't have to be drawn as often
2. More natural light means even fewer lights are needed
3. Fewer, more efficient lights generate even less heat
4. The more efficient AC can be sized smaller because of new windows and less lighting
5. The resulting reduction in end use electricity means even less electricity has to be generated because of transmission losses

These compounded benefits are not available if the strategies are installed separately.

There are several possible drivers of EE adoption. One would be traditional market forces. Homeowners can be convinced to buy new, more efficient technologies through advertising and word-of-mouth. An example is the widespread adoption of flat-screen televisions. There also regulatory drivers for EE adoption. These might take the form of laws that outlaw incandescent bulbs or new building codes that require better insulation in a new house. There are also utility programs that might provide incentive to the homeowner to make changes to their behavior to save money. Although this might be considered another form of market force, it represents a different form of motivation to adopt- the motivation of cost savings.

So if EE is easy and offers great payback potential why has it not been implemented? Actually, there have been improvements in the pursuit of EE. Since 1980, average residential loads have been reduced by 11% per square foot. Even greater improvements have been made in the commercial and industrial customer classes. The projections from the EIA for energy intensity have improved in the last 5 years by accounting for greater EE implementation. However, realizing the greatest improvements requires large up-front investments but with benefits that are spread out over the life of the system. The payback period can be greater than 10 years for some strategies. The actual nationwide results are also hard to measure because of the broad dispersion required for the strategy to be successful.

The barriers to the implementation of EE strategies can be grouped into 3 categories. There are ***structural barriers*** that prevent an end-user from having a choice. An example would be an apartment renter who cannot choose what model of air conditioner is bought. Another structural barrier is the problem of pricing distortions from low adoption rates due to regulatory issues. If the government has not allowed easy access to the grid or not forced utilities to pay reasonable rates for energy produced or energy saved by their customers, then few people will adopt EE practices.

The second barrier type, ***behavioral barriers***, include a lack of homeowner awareness of potential EE strategies. Lifestyle inertia (resistance to lifestyle changes) keeps people from changing to do new things like turn off the lights or pay attention to energy consumption and how they relate to power bills.

The third barrier is ***availability***. There are instances where the end-user wants to make a change but a lack of access to capital prohibits it. For example, if a homeowner must replace her heating system, a lack of savings or lack of banks that provide 'green' mortgages makes the new heating system too expensive.

According to Granade [45], the largest hurdle in addressing these barriers is the absence of a comprehensive policy. Because the barriers are extremely fragmented, it is difficult to foment change. Up to now there have been pilot programs, programs available only at the local level, and plenty of misinformation that has confused homeowners as to the benefits of EE. There are numerous categories of improvement but they are spread over millions of locations and billions of devices. This one fact guarantees that EE will not be a top priority for anyone because no one person can benefit greatly from just efficiency improvements. Granade suggests that the U.S. needs a national policy that recognizes EE as a potential source of energy in its own right . The study suggests the following **needed actions.**

1. Launch a complete EE program national and regional levels
2. Identify methods to offset up-front costs
3. Align the goals of the stakeholders- utilities, regulators, governments, consumers, manufacturers

**Proposed solutions** can be categorized into four areas.

1. information and education
2. incentives and financing
3. codes and standards
4. third party involvement to assist in implementation for the non-do it yourselfers

If these solutions are implemented at the national level then the three needed actions listed above will be accomplished and most of the barriers can be overcome.

In a study by Niemeyer, homeowners provided their view of the barriers to EE adoption [49]. The study sent a survey to 800 random homeowners in the state of Nebraska. There were 239 respondents that fit a diverse profile of location, sex, and education. The average age was 58 years but for most (~150 of the respondents), monthly utility costs were 'somewhat of a problem' or worse. For this group, the biggest three barriers for making changes to the energy efficiency of their home were:

1. Need financial assistance or discount on costs
2. Need added information
3. Need professional or additional assistance

These top three barriers in the homeowners' view would be addressed by the solutions suggested by Granade.

### Energy Efficiency: Pluses and Minuses

The minuses for EE strategies are few. Most of the negative aspects apply to a particular stakeholder. Four examples are:

1. Utilities will lose electricity sales from EE implementation that will directly affect their profit.
2. Manufacturers that sell products that are not energy efficient will certainly lose sales.
3. Homeowners that decide to implement EE ideas will most likely not receive the full payback due to the current trends in length of homeownership.
4. Landlords do not have any incentive to spend more money on more efficient products because they will not directly benefit from lower energy costs.

All of these minuses would exist in free market economies and require some modification to the structure of the market or behavior of the stakeholders in order to eliminate them.

The pluses of EE are too numerous to list in this paper but all can generalized into three broad advantages.

1. Lower electricity requirements for the U.S.
2. Slow the growth in Green House Gas emissions
3. Reduce the cost of operating a household

### Energy Efficiency and Harrisonburg Electric

In the model, EE is implemented by using inputs that represent the homeowner choosing to adopt a EE strategy. The specific strategies that the model uses are installing more efficient lighting, improving appliance efficiency, and improving the efficiency of the HVAC system. The cost structures of each of these strategies are included for both installation and electricity savings.

For HEC, there will be little benefit for implementing EE unless government incentives become available to the municipal electrical distributor. However, corporate goodwill is certainly important for most companies. Some utilities market heavily to their customers concerning new, efficient products but most are thinly veiled attempts to switch from natural gas consumption to electricity or to sell more devices that would use more electricity. HEC has little incentive to reduce consumption but does need to manage its corporate image. More discussion of the model and how it can be used by HEC occurs in the chapter entitled "The Model'.

### Summary of the Policies

The four policies or strategies presented in this paper are viable methods to address the current energy policy issues. Individually, they can provide some benefit to the U.S. but what if they are used in combination? What might the interaction be between FIT and TOU? Are the benefits additive or might they cancel each other's benefits out. Some have suggested that the four strategies will work to enhance each other thus giving us a stronger strategy[18]. To study this possibility, it is important to understand the characteristic effect of the four strategies. Each has benefits and drawbacks.

Below is a chart that summarizes the effect of individual strategies on energy load and costs.

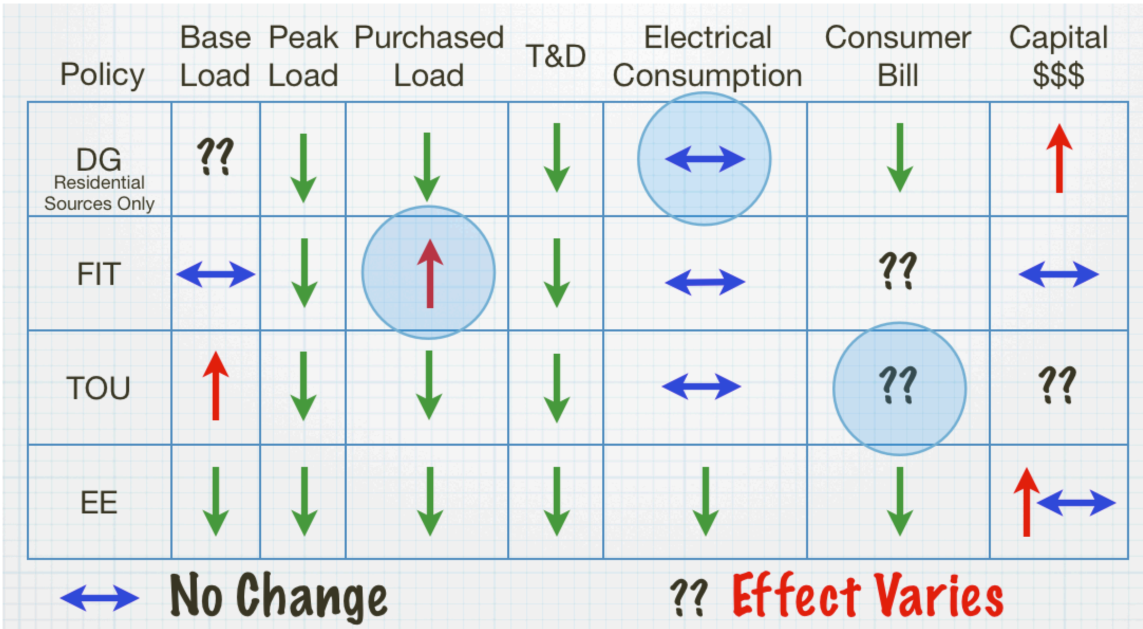


**Figure 8 - Individual Strategy Summary**

The Base Load, Peak Load, and Purchased Load columns in ***Figure 8*** represent the effect on electricity production and indirectly, the costs associated with these categories. The T&D column represents the amount of electricity that is conducted through the Transmission and Distribution infrastructure. The Electrical Consumption and Consumer Bill columns are measures of effects on the customer and the Capital $$$ column represents whether any capital expenditures are necessary to implement the policy. There is no differentiation between which party pays them. These costs could be paid by the homeowner, the utility, or a third party acting as an ESCO (Energy Service Company).

It is clear from ***Figure 8*** that there is no one best policy or strategy. Three interesting results from individual policies are circled in blue. The first is the fact that using DG still allows total electrical consumption to increase over time. There is no incentive from a DG policy that causes a reduction in consumers use of electricity. The second interesting fact is that under a FIT policy, utilities cost for purchased load will increase. The very nature of the FIT means that the utility will be forced to pay a levelized cost for the DG whether it be photovoltaic, wind turbine, or something else. These extra costs must be accounted for in the cost structure of the utility. The third interesting fact is that Time-of-Use can have either a positive or negative effect on the consumer bill. From the standpoint of the utility, a TOU rate structure is easy to implement especially as the Advanced Metering Infrastructure (AMI) or Smart Meter continues to grow. The outcome question depends on the view point of the consumer. There is no easy implementation for the homeowner to shift their load to other times of the day. The consumer can choose to wash laundry after midnight but how many people actually will? There will have to be some residential infrastructure changes made to make a TOU policy beneficial to the homeowner. This change could be some type of energy storage implementation. Many electrical distributors in the U.S. have tried to implement TOU rates. Some are still offered but other have been abandoned for just these reasons. Customers end up with higher bills for lack of proper implementation of the strategy.

Finally, depending upon how these four policies affect the utilities cost and income structures, there will be some impact from the regulatory process. Simply shifting utility equity from retired, large scale generating plants to smaller scale distributed generation might impact the regulators' view of allowed rate of return for the utilities and what is considered "used and useful". If there is impact on the profit margin by implementing these policies, there will also need to be some adjustment to the rates charged by the utilities. If a FIT were implemented and the program was highly successful, then the entire utility customer base will be impacted by the FIT. The costs associated with paying out the FIT rates will need to be recovered. In the most successful FIT implementations, this is achieved by raising all rates. These issues and any other regulatory questions will certainly need to be a part of any change in how the utilities conduct their business.

## The Model

### Why System Dynamics

System Dynamics (SD) modeling and the Stella software platform were chosen for this paper for several reasons. The System Dynamics methodology is typically used in long-term, strategic models of complex systems. Examples of these complex systems are corporate strategic planning, biological systems, or human/environment systems. SD usually employs a high level of aggregation of the objects being modeled and is not concerned with fine details. In SD, individual attributes of an item are not accounted for, only their behavior as a group over time.

The time-tested metaphor of SD is the model of a bathtub. It has inflows that fill it up and outflows that empty it. SD doesn't notice that the inflow might be blue or red, only that it is all water. Over time, the behavior of the volume in the tub is of interest to the modeler. Is the tub filling up, emptying, or is its level staying the same? What happens when a particular flow doubles in quantity? What happens if the outflow is delayed for some amount of time? These dynamics are of interest to the SD modeler.

Other attributes might be included in the model such as the temperature of the water or the color of the water or even how much that water costs. These attributes would be represented as separate stocks. The modeler would have a temperature stock and a color stock with different flows for inputs and outputs.

Many of the dynamics in this paper's model could also be represented by another methodology called Discrete Event System (DES) based modeling. In Discrete Event, each object is modeled individually as an entity. Typically the modeler ignores many "physical level" details, such as exact geometry, accelerations, and decelerations. Discrete modeling is generally considered process-centric modeling. Process-centric modeling suggests that this process represents a linear sequence of operations such as an assembly line. This method is used widely in the manufacturing, logistics, and healthcare fields [50]. According to Sweetser, there are no feedback loops explicitly accounted for in a DES model and the focus is on the measurable aspects of the process [51]. He admits that there are many systems that can be modeled using both DES and SD methodologies but that for DES the numbers are important and for SD the behavior and structure are the focus. The modeler may have to adjust the detail of the model but similar outcomes can be achieved with many types of models as suggested in Ozgun[52].

The model in this paper needs to focus on both behavior and quantities due to the complexity of the system. Electricity costs and consumption are quantities that represent outcomes of different strategies and behaviors. How consumers and utilities respond to these outcomes are also a necessary part of the analysis. What makes this model somewhat unique is that there are multiple timescales of interest. In the limited experience of this modeler, the behavior of interest is usually related to one timescale. It could be seconds for a biological system or decades for a government policy. A request from the U.S. Department of Energy in 1992 resulted in a report generated by the National Research Council concerning how a national energy model could be implemented. In the discussion of the National Energy Modeling System (NEMS) architecture, the authors noted that differing time horizons require different analytical methods. For that reason, they recommended producing three different models for the three time horizons of interest; short-term (<2 yrs), medium term (between 2 and 25 yrs), and long term (>25 yrs)[53]. However, the hourly consumption of electricity, the daily swings in the total load, the seasonal cycle of the demand for electricity, as well as several multi-year behaviors are all of interest in this model. If they all can be implemented into one model correctly then why not? The only drawback from these multiple time horizons is the requirement to run a small time step (hourly) for multiple years (>10) to see all of the behaviors. Each year has 8760 hours so 10 years requires 87,600 time steps. Each run of the model will take in excess of 15 minutes. This delay limits the number of tests that can be quickly run for the client, HEC.

*Note: Based upon the research questions for this thesis, a limit is placed on the runs of a single year. The behaviors of interest to HEC currently are the immediate effects of the strategies on their costs and the total bill to the residential customer. The model however, is built to allow a look at other behaviors in future work.*

In the U.S., the electricity demand swings from peaks to valleys every day as discussed in the TOU chapter. Utilities must plan for changes in these daily peaks throughout the year because the peak during summer is at a different time and has a different value than the daily peak in April or January. The capacity margin that utilities must maintain to handle these peaks requires multi-year plans because new capacity has traditionally taken more than five years to install. Studies have also shown that while there is very little elasticity in the price of electricity for consumers in the short term (less than 1 year) there is definitely some response to higher or lower prices in the long term [54]. As appliances or HVAC equipment require replacement, consumers will make purchase decisions based upon such things as cost of operation from electricity. This behavior stretches into decades.

Measurement of electricity loads and rate structures will be important. The timing of the 'flows' of cost and electricity will interact with each other. Human factors such as technology adoption rates will be inserted into the model to show behavior over longer time periods. The diversity of these behaviors make the topic of this paper complex but the nature of these behaviors and how they interact is the primary focus and is why System Dynamics has been chosen. How all of these behaviors affect each other will help determine the outcomes from implementing the four strategies of Distributed Generation (DG), Feed-in Tariffs

(FIT), Time of Use rates (TOU), and Energy Efficiency (EE). The analysis will address any significant effect from feedback and what time frame is important.

Although other modeling methods can account for system feedbacks and their dynamics, System Dynamics is not only robust in showing the structure of a system's feedback but also in showing the effects of the feedback. Because of System Dynamics' use of Causal Loop Diagrams and Stock and Flow structures, a system's feedback can be represented graphically and expressed algebraically. Much of this paper's model could be represented in a spreadsheet, although a very complex, convoluted spreadsheet. However, a spreadsheet does not visually express the causal links between objects in the model. The connections are hidden within the algebra and inter-cell references. The Stella platform offers marked improvement over spreadsheets in terms of programming and transparency. It is a software product produced by ISEE Systems expressly for SD models. Its graphical interface brings the advantage of being able to see the linkages between elements of the model so the user can easily visualize and verify what parts might affect others.

In this paper's model, there are several feedback effects that will be included in the design. The first is the action of the regulatory system. Investor owned utilities are regulated by state or regional authorities to keep their monopolistic nature in check. If utilities profit moves outside of a predetermined range, then the regulatory body steps in to adjust rates or other income streams. The utilities must remain viable and be guaranteed a minimum return to their investors. Likewise, utilities must not be allowed to profit too greatly by exerting market control over a necessary commodity. In this model, the regulatory aspect will simply be a check on profit. Because Harrisonburg Electric is a municipally owned utility, it does not fall under the Virginia regulatory body, the State Corporation Commission. In this case, there is no regulator other than the HEC Commissioners as they respond to public concerns about rates and work to make sure HEC remains a viable business.

The second feedback implemented in the model is the customer response to the success of the Energy Efficiency strategy. If the payback of the EE investments is significant then the adoption rate of customers will increase. Because adoption rates are not linear responses to price or profit, the shape of the adoption rate curve will ultimately determine how much EE gets implemented. If the cost of EE changes for reasons such economies of scale or improved technology then adoption rate will change. For example, LED lighting is by the far the most efficient lighting source for residential use. The price for LED lighting per lumen has dropped from about $10 in the 1970's to $1 in the 1980's and to about $0.10 in the 1990's [55]. These improvements are expected to continue through improved LED efficiency and economies of scale. This additional causal link to the price of the EE investments is not implemented for this paper but could be included in future work.

The third feedback originally considered but ultimately not implemented makes the link between HEC and its desire to implement the strategies. There will be capital costs associated with the TOU, DG, and EE strategies. The FIT strategy is a secondary step for DG and will have some administrative costs but a properly implemented FIT should not have capital costs that are not already covered by the DG implementation. From the TOU, DG, and EE strategies, HEC will see changes in their profits based upon which of the strategies are used. If their profits can increase to the point where the regulatory adjustments kick in, then the excess could be spent on more capital equipment to implement more of the strategies. This use of the profits would mitigate changes to the rate structure for the residential class customer. This feedback was not implemented after final discussion with HEC. HEC has no long range planning so this feedback is insignificant to them currently. Further development will be necessary to make this portion of the model useful to HEC.

These three feedback effects are only a sample of the dynamics that occur in this system. They were chosen as the starting point for discussion with the client, HEC. Much future work is possible as the needs of the client become more apparent. Feedbacks not implemented in the model at this time are the causal links associated with longer time horizons. These could be implemented into this model while acknowledging the delays to run multiple simulations as noted above. Perhaps a more practical implementation of these particular feedbacks would be to create a more aggregated model that does not include the hourly data and simply includes the behaviors specific to the long term. In particular, other feedbacks not included in the analysis in this paper are:

- The link between greenhouse gases and a warmer climate that would affect the demand curves of the customers; If it is hotter then the residential customer will run more air conditioning and peak demand will increase thus creating a need for more fossil fueled electricity generation. Most projections point to this effect taking decades to change electrical demands.

- The effects from construction delays associated with new generation plant construction; As demand continues to grow as projected, utilities will have to construct new capacity. The traditional, centralized plants require more than five years to plan, permit, build and bring online. Because the model is based upon HEC, there is no need for new capacity in the near future.

- The limitation of the current Transmission and Distribution system; Although this is not a problem for HEC, some utilities have T&D systems that are nearing capacity. As demand grows and the systems continue to age, more capacity will be needed or limits will have to be placed on total electricity delivered in the form of brownouts or even rolling blackouts.

- The link between a FIT policy and its affect on installation costs of the required DG equipment; One of the main purposes of a FIT is to reduce the total installation cost of DG such as photovoltaics or wind turbines. This result, as shown in FIT programs in Europe and Gainesville, FL, comes from creating more expertise and competition in the installation of these technologies and also from the increase in economies of scale in their manufacturing.

## The Model Structure

### Building the CLD

To build a System Dynamics model, the process usually starts with a Causal Loop Diagram (CLD). A CLD breaks a system down into the components that are of interest to the modeler. In the case of this paper's model, the beginning point is the diagram below. ***Figure 9*** shows a simple view of the distribution of electricity. Electricity is generated by a utility and it is sold to the customer, who then uses it. The boxes represent stocks or quantities of things. The double-line arrows with valve symbols are flows which represent movement to or from a stock.

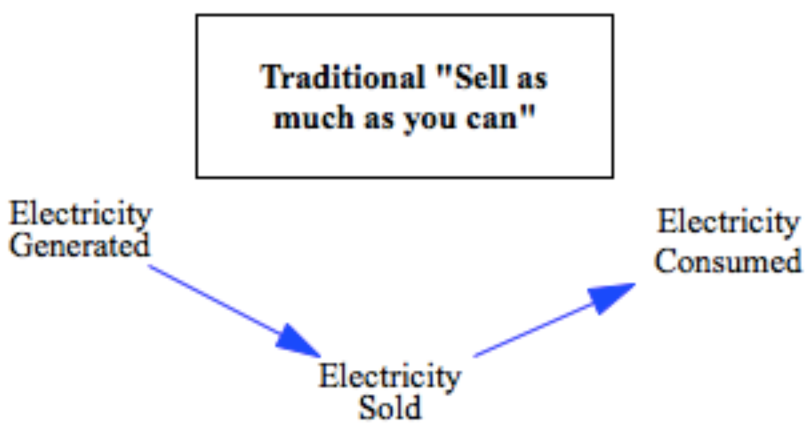

**Figure 9 - CLD Starting Point**

To make the model as accurate as possible and complete as necessary, more components are added to the CLD that represent the behavior that is to be analyzed. ***Figure 10*** shows that there are two components that contribute to the Generation stock. There may be others but for most utilities, their generation comes in two distinctions, baseload and peak capacities as described in the TOU chapter. Also included in ***Figure 10*** is a recognition that the electricity demand is growing.

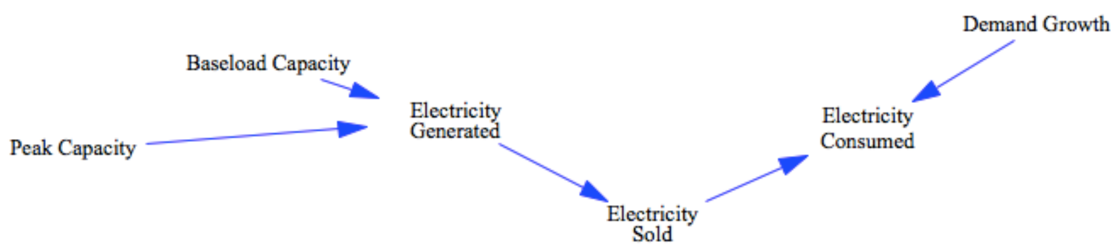


**Figure 10 - CLD with added components**

The variable ***Demand Growth*** is modeled as the projected annual growth and is derived from the U.S. Department of Energy's EIA projections. By adding these three new variables, the model immediately becomes more dynamic.

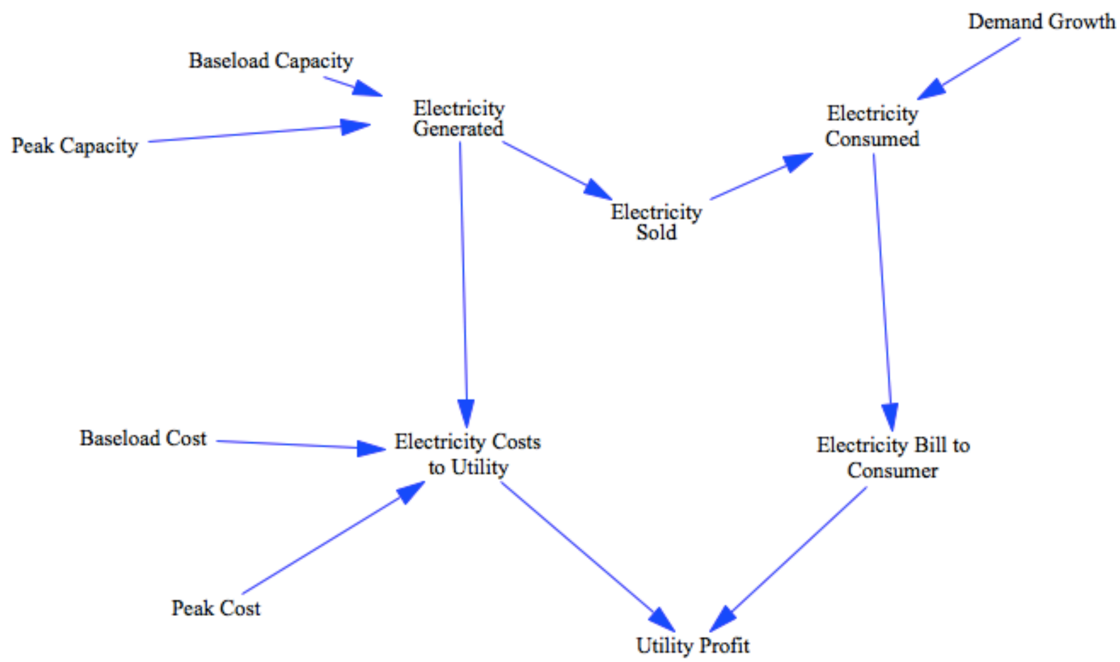


**Figure 11 - CLD with financial aspects**

In ***Figure 11*** above, the model now includes some financial aspects of the system. The stocks added are representations in dollars of the utility's generation costs, the customer's electric bill, and the utility's profit from the difference of the two. The two auxiliary variables for utility costs help break out the difference between baseload and peak generation sources

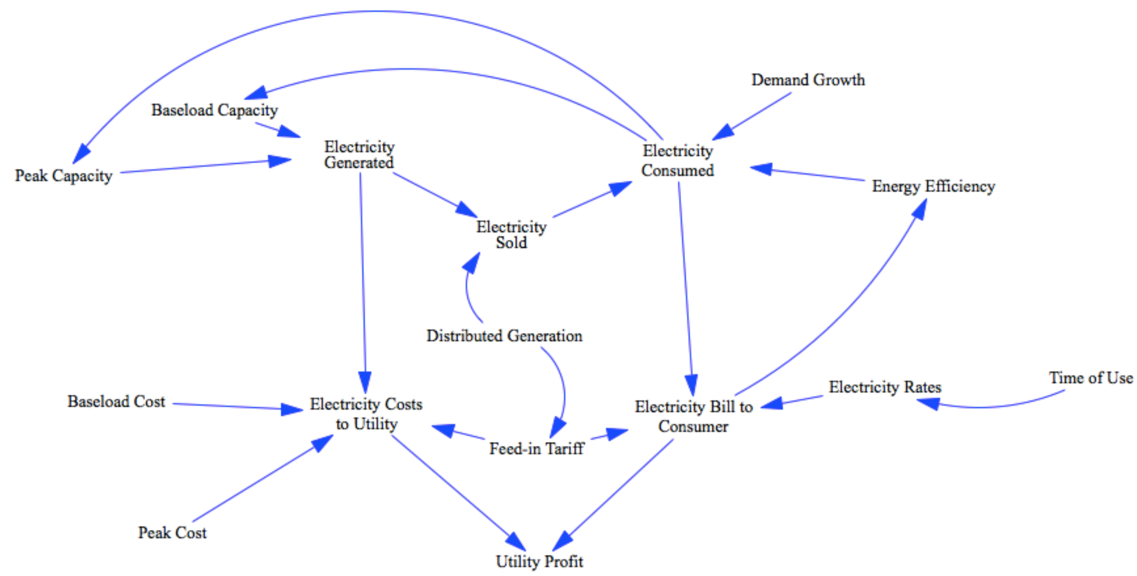


**Figure 12 - CLD showing the four strategies of this thesis**

The final CLD is shown above in ***Figure 12*** and includes the four policies or strategies that are the basis of the analysis in the simulation. From the causal arrows connecting the four strategies (DG, FIT, TOU, and EE) one can see which stocks are affected. TOU is the implementation of a new rate structure. EE directly affects the amount of electricity that is consumed which then affects the customer's bill. To show how a feedback loop would be considered, the consumer's bill would then have some affect on whether changes were made to the EE strategy. DG would not directly affect the amount electricity that is consumed but how much is sold by the utility. DG would also have direct impact on a FIT if it were implemented but the FIT itself would only directly affect the consumer's bill and the utility's costs.

As described in the previous section, there are many behaviors and components that could be addressed by this model. The author has made every attempt to define the included behaviors and list some that have intentionally been left out. If the reader discovers omissions or even undiscovered behavior that should be in the model please contact the author, Brooks E Taylor at TaylorBE@Dukes.jmu.edu.

### Building the Model

The model for this thesis was constructed using ISEE Systems Stella software. A baseline model was first created to validate the cost and income structure for HEC. After HEC's customer load data and cost information was gathered, the baseline model was demonstrated for an executive of HEC. The structure of the model in terms of the mechanisms for costs and sales was verified. It was also concluded that the results were compatible with the real system. Since real, historical data was used, the outputs of the model were able to be compared to the real outcomes in terms of total consumption and profit. Below (***Figure 13***) is a picture of the Stella model for the baseline scenario.

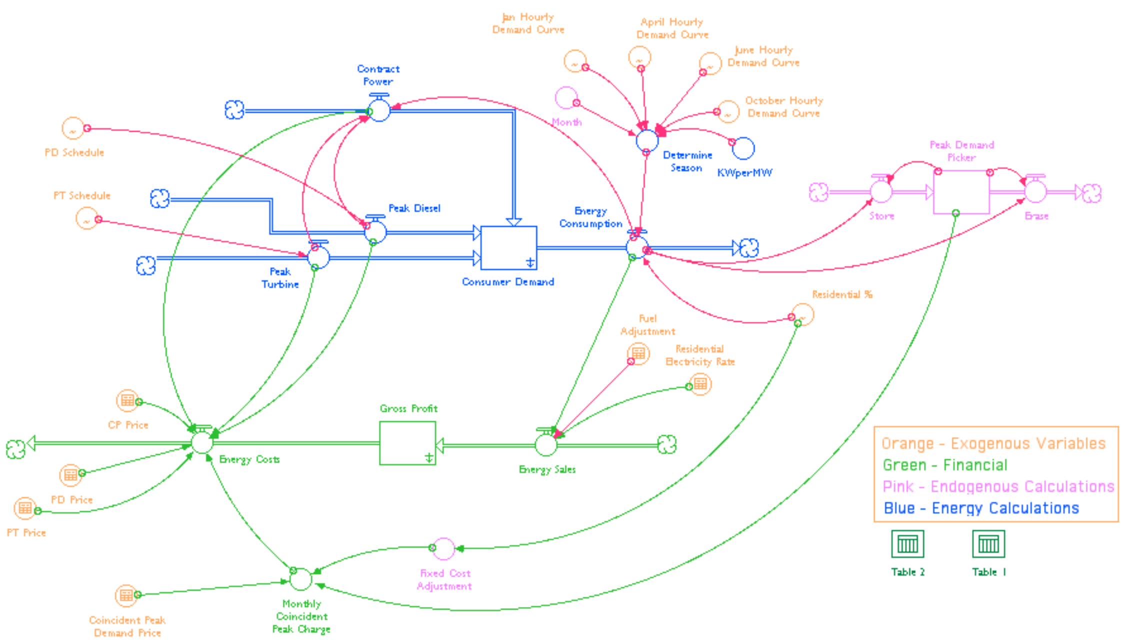


**Figure 13 - Baseline Model using Stella software**

There are several notable features of the Baseline model. The Peak Demand Picker is the logic that picks the Peak Demand hour for each month and then uses it to calculate HEC's Coincident Peak Charge which can be more than 50% of the utility's total electricity cost. Another is the characteristic that the Peak Diesel and Peak Turbine generators are currently used very little by the utility. The cost to run the generation is high. Also, the supply contract that

HEC is currently under prohibits the use of the generation capability to mitigate its peak demand charges.

The third notable facet of the model is that the customer load is modeled by representing two characteristics. The first characteristic is the way total demand is calculated each hour of a month for each of the four seasons. The model currently uses typical January hourly data to represent the winter months of December through March; it uses typical April hourly data to represent the 'shoulder' months of low load swings of April and May; it uses typical June hourly data to represent the summer months of June through August; and the model uses typical October data to represent the milder 'shoulder' months of September through November. This calculation is made in the '***Determine Season***' variable. The reason for these representations is to limit the size of the sample data but also to allow for flexibility when the model is adjusted for other regions and utilities. The second important characteristic of the customer load calculation is the fact that the model is using only the percentage of the total load that represents the residential customer class. This percentage changes throughout the year so the variable is represented as a table of month versus percentage values. Therefore the Residential class portion is calculated by multiplying the total monthly load by a percentage that is the residential portion. This table of percentages is found in the variable '***Residential %***' The reason the percentage changes is because residential loads in the winter months have a large component of water heating and electric space heating that commercial customers do not. In the summer, the commercial class has a larger percentage because their air conditioning loads are much larger than residential A/C.

The complete model for this thesis is much more complex than the Baseline. In order to accommodate all of the necessary aspects, the model uses modules to break the logic into components. The current model has five modules. They are called Utility Power, Utility Economics, Customer Power, Customer Economics, and Regulatory. The Power modules hold the logic concerning generation and consumption of electricity. The Economics modules hold the logic that calculate the utility's costs and the customers' total bill each month. The Regulatory module contains the current logic for determining whether the utility's percent profit is out of a pre-determined range. All of these modules share information through their variables and causal links. Below (***Figure 14***) is the highest layer of the model showing the five modules and the interconnections of information that is shared between them.

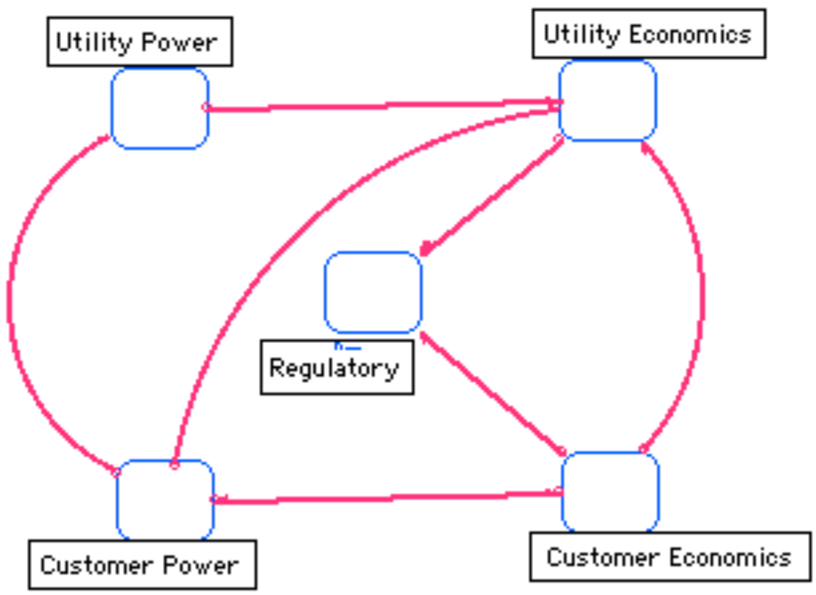


**Figure 14 - Thesis Model, top level**

The ***Utility Power*** module uses the same structure as the Baseline model represented by the blue components in ***Figure 13***.

The ***Customer Power*** module (***Figure 15***) contains the more complex consumption calculations for how a customer uses electricity. These calculations and structure include the peak shifting capability that will be necessary to test the TOU strategy. The TOU strategy implements a peak shifting or peak shaving plan that allows the utility to reduce power consumption during peak hours and move that consumption to off peak or trough periods. These usually occur during the night after midnight. The model must find the peaks and troughs in the data and track them. It does so by keeping the daily maximum and minimum values for the previous seven days. What the model supposes is that the utility will store energy in some form during the troughs when its load is at its lowest point. The model then releases that energy when it finds a potential peak and its load is going above the seven day average peak. By lowering all peaks above the seven day average, this method will have the effect of lowering the Coincident Peak that the utility will be charged for at the end of the month. For HEC, the reduction of just the residential peak load by 10% would result in monthly savings of tens of thousands of dollars.

The ***Customer Power*** module also contains the logic for implementing the DG sources for the FIT strategy which includes DG for wind, photovoltaic, and Combined Heat & Power (CHP). There many other possible sources for distributed generation such as small hydro, fuel cells, or concentrated solar so the three chosen are simply representative of the style. They are small and located close to the electricity end user.

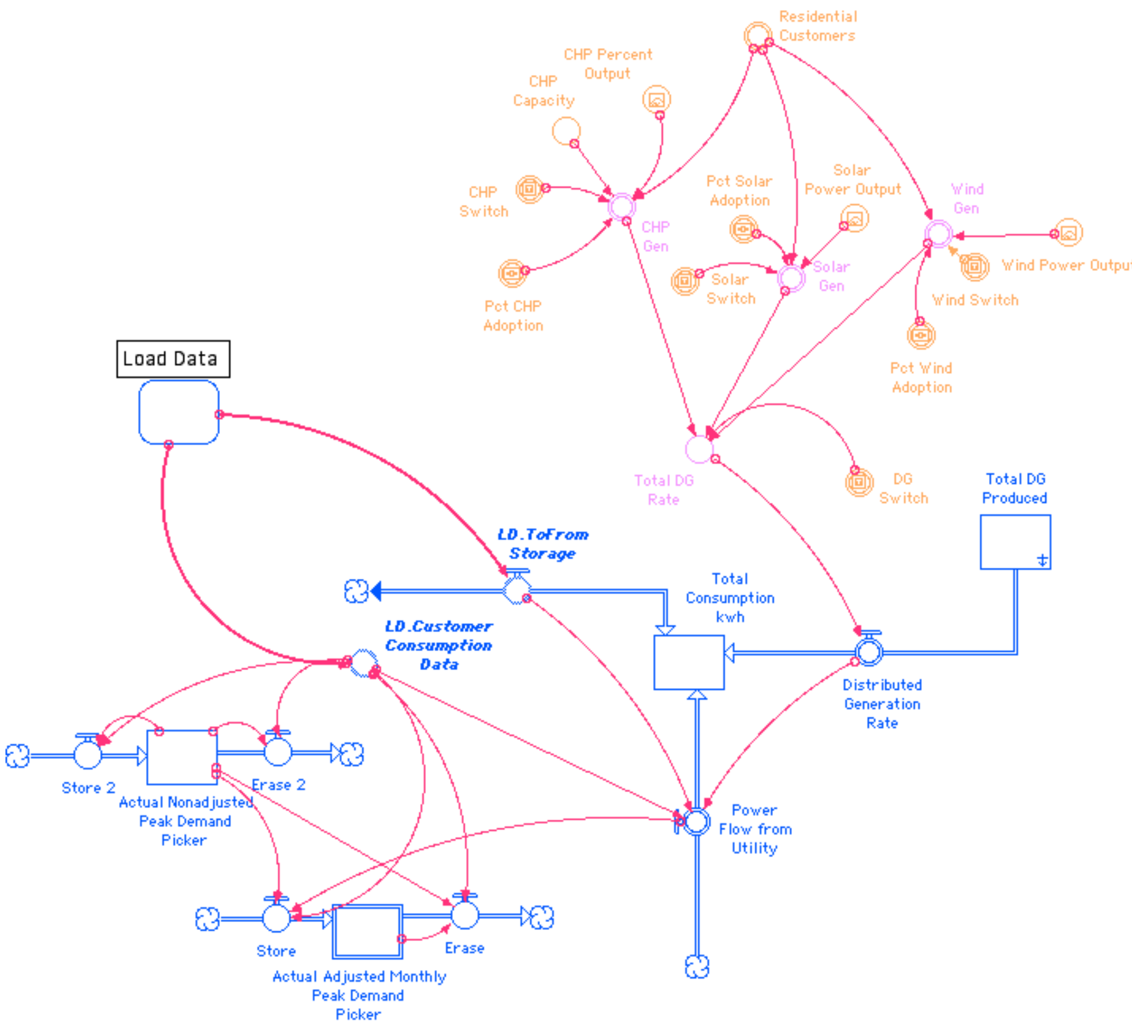


**Figure 15 - Customer Power module**

The ***Utility Economics*** module looks very similar to the Baseline model structure. The new module, shown below in

***Figure 16***, now includes the cost of the DG and logic that tracks the costs of the DG/FIT implementation. Because the FIT is essentially a contract to purchase power from the owner of the DG, its costs will directly add to the cost of electricity for the utility. If the model runs for the life of the FIT then the utility will see these costs diminish to prices that are more comparable to the generated power that the utility produces itself or in the case of HEC, purchases from wholesale producers.

The capital costs required to implement the strategies result from costs associated with the DG and peak shifting. These costs would include the installation costs of the strategy and any operation and maintenance costs if they are significant. In this implementation of the model, the only O&M costs are associated with the CHP because of the regular maintenance and fuel costs required to operate the micro-turbines. The model does not assign these costs to a stakeholder. It merely breaks them out for the sake of strategy analysis.

Finally, the new module includes some new annual accounting that can be used for multi-year analysis, which for this paper will not be utilized.

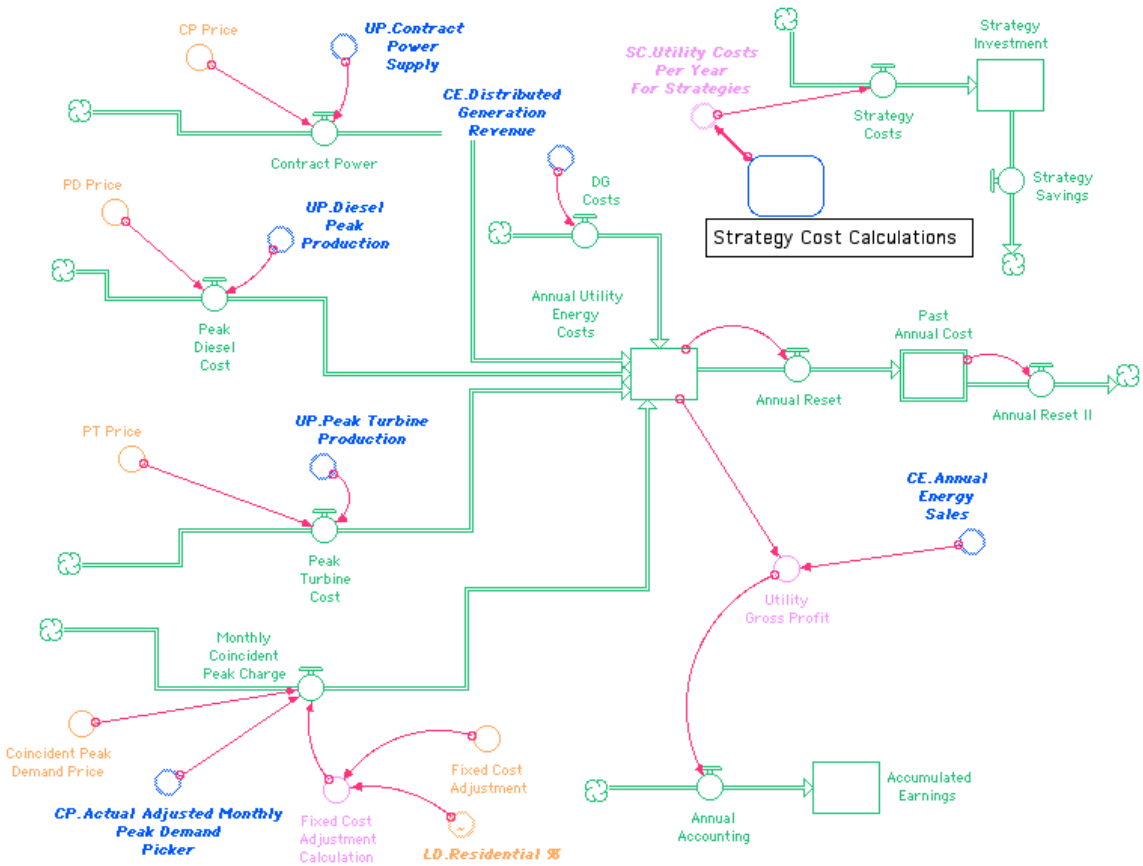


**Figure 16 - Utility Economics module**

The ***Customer Economics*** module is made more complex by the FIT income produced, the savings from EE, and the changes to '***Annual Energy Sales***' (found in ***Figure 17***) due to additional logic for the electricity sales rate structure.

TOU rates are offered by numerous utilities around the U.S. The author first incorporated the rates associated with Dominion's Virginia Power. Contrary to prior experience, the TOU rates negatively impacted the profit of HEC. After discussion with HEC, it was determined that this result was due to HEC's cost structure. A majority of the electricity in the U.S. comes from investor owned utilities that own their own generation and therefore have baseload capacity and peak load capacity. TOU rates would allow these utilities to reduce their costs for the peak load capacity which is much more expensive. HEC does not have the same structure. Its capacity, what it buys from its supplier, has the same cost every day of the year regardless of when it uses it. Therefore HEC has less savings from reducing the demand during peak times. In trying to find a more 'HEC friendly' TOU rate structure, the rates from Alabama Power's TOU or RTA (residential time advantage) were used. The rate is graphically shown in ***Figure 6*** in the Time of Use section of this paper. The structure required the use of three time periods during the year. These were the '***TOU Rate Summer***', '***TOU Rate Winter***', and '***TOU Off Season***'.

The other pieces of the rate structure besides the '***Normal Rate price***' are the '***Fuel Adjustment***' charge and the '***FIT Rider***'. The '***Fuel Adjustment***' charge is how most utilities recover annual changes to the cost of the fuel needed to generate power. The adjustment has been as high as $0.02279 in 2008, as low as $0.01216 and is currently $0.01723 per kWhkWh. The '***FIT Rider***' is the model's method for cost re-covery for the FIT policy. When enabled through the '***FIT Recovery Switch***', it adds a charge to the overall rate that increases revenue for the utility and can offset the FIT payments to the DG owners. For analysis in this paper, the Rider is not used because it hides the cost of the FIT and its set value is a debatable quantity.

The EE savings calculations are not included in the '***Annual Energy Sales***' variable. The required reduction from the EE strategy comes from the ***Customer Power*** module calculations by the amount of power sold by the utility '***Power Flow from Utility***' that is reduced by EE. The FIT produced power is added into the '***Hourly Electric Sales***' because it becomes another generation source for the utility and is sold to all customers on the grid at normal rates. The '***Accumulated Effic Savings***' and '***Customer Revenue from DG***' are tracking their respective variable totals for analysis. These values are not shared by the whole residential customer class but only benefit those that implement EE or install the DG under the FIT agreement.

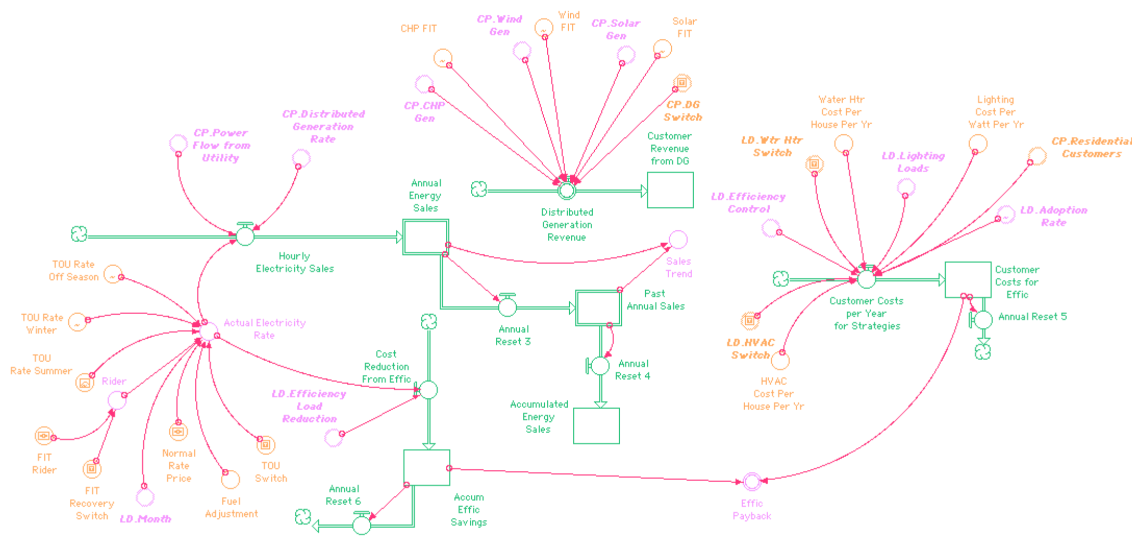

**Figure 17 - Customer Economics module**

The fifth and final module in the current version of the model represents the behavior of the regulatory action on the utility (***Figure 18***). The thesis model uses data from Harrisonburg Electric, a municipally-owned electric utility. In Virginia, this means that it will not fall under the auspices of the state regulator, the SCC. The regulatory function in the model will instead be representative of the public discourse that might happen if the utility began to reap profits that its citizen-customers deem too high. HEC's charter does not provide any government entity oversight powers so public outcry would be the only external pressure to adjust rates. However, in the last meeting with HEC, there was no concern that this module would have any affect on policy or rates. HEC's efficiency and excess capacity allows management to not be concerned with long term planning greater than a few years which is the timeframe necessary for the module to take any effect. HEC only had interest in the one year model.

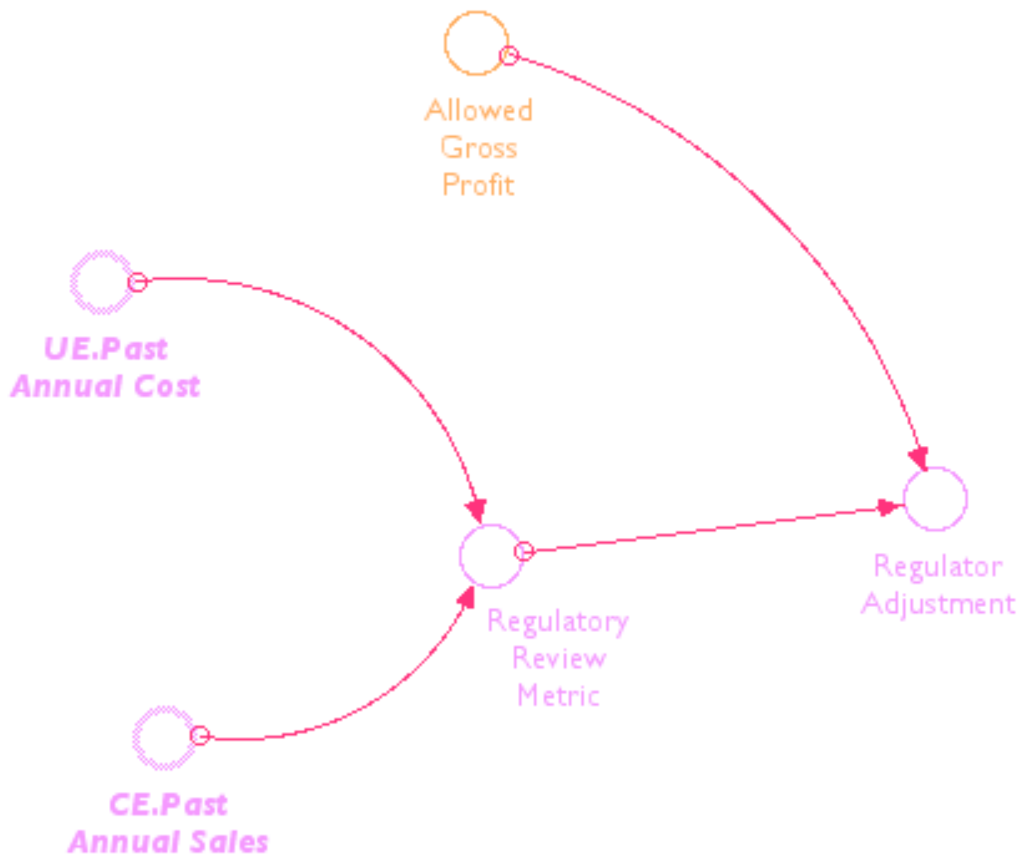


**Figure 18 - Regulatory module**

### The Starting Point for the Simulation

As with any model, the user must acknowledge that the model is only as valid as its structure and input data. Even with these two pieces, the model still only represents the modeled system and cannot be thought of as an exact replacement for the real-world system. The goal of this thesis and the associated model is to create a tool that utility operators can use to view possible outcomes for their sales and profit with the application of the four chosen strategies. This tool is not meant to give precise measurement of these parameters but to show comparison between 'business as usual' practices and changes that include the TOU, FIT/DG, and EE policies separately and in combination.

The author, through interviews with an HEC executive, created this model by starting with the Baseline model. This model included data from HEC that was then used to verify model structure. When the output of the model agreed with actual results from HEC and the cost and sales structures were validated, the author then modified the model by adding structure and exogenous variables that allowed for the new strategies to be tested. Each strategy was tested separately by (1.) allowing HEC to acknowledge its structure and then (2.) analyzing the output for veracity and effect on the costs, power quantities, and sales of electricity. Because no person involved with this project had extensive knowledge of these effects, they could be only (3.) checked for practical soundness. In other words, do the results make sense? In all cases, model structure was changed until these three criteria were satisfied.

The appendix at the end of this paper lists every exogenous variable used in the model. Along with a brief description of its purpose or meaning, there is a reference to the source of the value that was actually used. However there are a few variables that need to be mentioned in this section so the reader can have a basic understanding of the model and its results.

- The first important note is that for the purposes of this model, one year is calculated as 12 months times 30 days times 24 hours. This in effect shortens the year by 120 hours or 5 days which represents 1.4% of a year but this simplification makes the structure of the model for tracking these variables much simpler. It also makes implementing the seasonal data simpler.

- The seasonal load data was provided by HEC and is real data from 2010 and 2011. HEC records its total load every hour along with other information that is important to its operations. This data was provided to the author in the form of computer line-printer outputs.

- All data associated with HEC's purchase of power, operating their standby generators, and normal rate structure came directly from an HEC representative.

- For the Time-of-Use rates, the author attempted to use to use Dominion Virginia Power as a source. Their rates have no shoulder or off-season months. All months are categorized as either winter or summer and this form was originally implemented. When the trial runs began, it became obvious that these rates would be detrimental to HEC's gross profit. Understanding the corporate strategy behind TOU rates and how they are designed is hard to rationalize between individual utilities so it is difficult to know in what form the rates should be. The author switched to the Alabama Power rates hoping to see some better outcomes for HEC. The model structure was changed to add the '***TOU Rate Off Season***' to accommodate this additional part of the rate.

- In the peak shifting portion of the model that augments the TOU, there are several implementations that were considered. Utility scaled projects such as pumped-storage did not fit this application. There are battery-based systems that can store large amounts of energy and then be allowed to discharge back onto the grid during peak demand. An all-electric car could also serve this purpose. However, for the simplicity and cost requirements that HEC seemed to desire, a parallel water heater system is applied to the model. The way it would function in practice is that when the model detects a trough during the day it turns on the parallel heater to make sure it is full of hot water. This would usually be during the middle of the night and the unit would not be able to be turned on at any other time. When the model detects a peak then a controller would turn off the original water heater so it could *not* add to the peak load and the homeowner would be able to draw hot water from both tanks without a loss in capacity. This method of implementation would be the least expensive of those considered. The only drawback is that this method would work during the highest peaks in the winter but might not be as effective in the summer. Further study would have to be conducted to determine the contribution that water heaters provide to the peak load during the summer months.

- For the Feed-in Tariff, there were three policies in North America that were considered; The Gainesville, FL FIT, the FIT in Ontario Canada and the state-wide FIT in Vermont. Vermont was chosen because the author felt the environmental factors were similar and also because the Vermont FIT had rates for DG sources other than solar photovoltaics. The Vermont FIT is still relatively new so there has been little analysis of its success. However, the program was modeled after programs in Europe that have show great success in increasing the installations of renewable energy and reducing their overall installation costs.

- For the Demand-side Energy Efficiency, the main implementations that have been used are, in the view of the author, the best representation of possible solutions.

As discussed in the EE section of this paper, there are two types of EE. One is energy conservation which is the behavioral modifications that allow someone to use less energy. Examples are combining car trips to save gasoline or turning out the light when you leave the room. The second is actual improvement in efficiency by implementing physical changes to lower the consumption of energy to achieve the same task. Examples would be using more efficient lighting or driving a compact car instead of a SUV. The first is of interest in the model over the longer time frame. The second is of more interest in the short term. Because HEC's interest is short term at this time, the physical method is what is implemented. Three representations are used; using ground-source heat pumps, using a highly efficient, heat pump water heater, and using LED lighting in the home. All of these are viable alternatives that are available to homeowners today.

All of these elements allow the modeler to run the model and provide useful output to the client, Harrisonburg Electric Commission, without providing for unlimited choice in input parameters.

## Answering the Questions

**1. How might combinations of the strategies of Time of Use pricing, Feed-In-Tariffs, Distributed Generation, and Energy Efficiency affect HEC costs, customer electric bills, and overall electrical consumption in the HEC residential class customer base?**

From the scenarios shown above in ***Table 1***, it is apparent that the different strategies affect the metrics (profit, electrical consumption, etc.) by the same quantities if activated during any run of the model. There is very little interaction between the strategies. Only when a combination of strategies that reduced HEC CP charges (the peak demand charge from Dominion) and lowered the amount of electricity sold, did a cumulative effect appear.

| | Strategies | Utility Gross Profit | Utility Annual Energy Costs | Utility Annual Energy Sales (customer bill) | DG Energy Costs | Annual Strategy Costs | Total Electricity Consumption | DG kWh Produced | Annual Savings from EE | Annual Cost of EE |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | None | $5,816,371 | $14,038,597 | $19,854,968 | 0 | 0 | 209,351,690 | 0 | $0 | $0 |
| 2 | Peak shifting | $6,316,053 | $13,541,287 | $19,857,340 | 0 | $357,181 | 209,351,690 | 0 | $0 | $0 |
| 3 | TOU-no shifting | $823,201 | $14,038,597 | $14,861,798 | 0 | 0 | 209,351,690 | 0 | 0 | 0 |
| 4 | TOU w/ peak shifting | $1,155,961 | $13,541,287 | $14,697,248 | 0 | $357,181 | 209,351,690 | 0 | 0 | 0 |
| 5 | FIT(1) | $5,047,824 | $14,807,145 | $19,854,968 | $1,152,219 | $918,000 | 209,351,690 | 4,800,914 | 0 | 0 |
| 6 | EE (2) | $5,425,826 | $13,219,370 | $18,645,195 | 0 | 0 | 196,595,787 | 0 | $1,209,897 | $1,816,263 |
| 7 | EE (3) | $5,693,972 | $13,781,846 | $19,475,818 | 0 | 0 | 205,353,910 | 0 | $379,189 | $117,584 |
| 8 | Peak Shifting & EE | $6,193,653 | $13,284,536 | $19,478,189 | 0 | $357,181 | 205,353,910 | 0 | $379,189 | $117,584 |
| 9 | Peak Shifting, TOU, EE | $1,128,911 | $13,284,536 | $14,413,447 | 0 | $357,181 | 205,353,910 | 0 | $283,821 | $117,584 |
| 10 | EE, FIT | $4,925,424 | $14,550,394 | $19,475,818 | $1,152,219 | $918,000 | 205,353,910 | 4,800,914 | $379.189 | $117,584 |
| 11 | ALL | $360,364 | $14,053,084 | $14,413,447 | $1,152,219 | $1,275,18 | 205,353,910 | 4,800,914 | $283,821 | $117,584 |

**Table 1- Results from Model Runs**

*Notes*

*1. This FIT implementation uses only PV and includes no FIT recovery mechanism for the utility.*
*2. All three EE implementations were used.*
*3. Only LED lighting was implemented.*

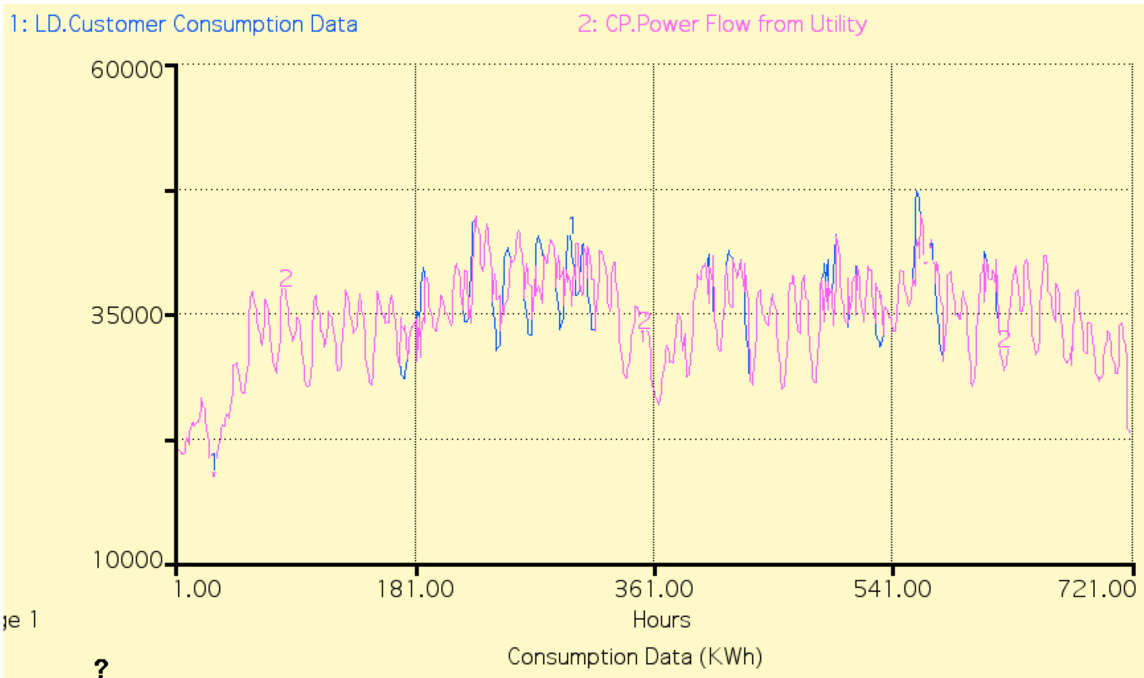


**Figure 19- Consumption Data for Run number 2 which only includes the Peak Shifting for HEC (1 month)**

The graph in ***Figure 19*** shows where the load is shifted at its peaks and troughs during Run #2. The blue that shows through at the top of a curve is where customer consumption remains the same but that the amount of energy sold by HEC is reduced. This difference comes from energy being withdrawn from storage that HEC bought from its supplier during an off-peak or trough in demand. Where the blue shows through at a trough is where HEC is buying more KW than the customers are using because this extra power is going into some form of storage. Notice the largest peak at about time 560 is reduced by this strategy. The net effect is the significant reduction in HEC's CP demand charge for this month.

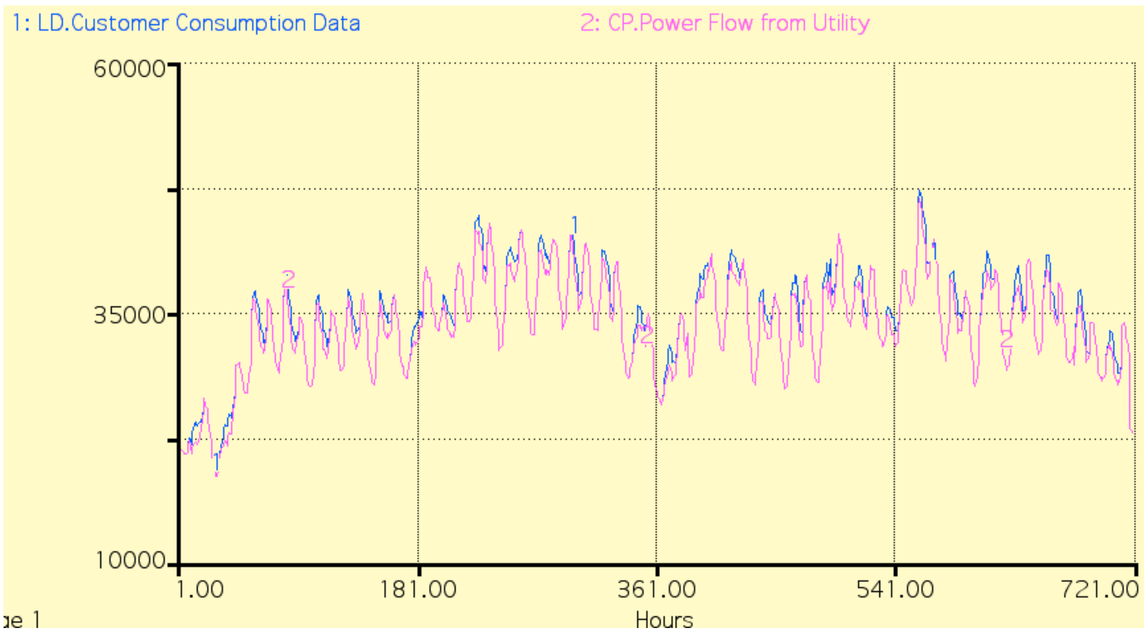


**Figure 20- Consumption Data for Run number 5 which only includes FIT from photovoltaics (1 month)**

The graph in ***Figure 20*** also shows where the load is shifted at its peaks but not at the troughs in Run #5. During this run the peak shifting is coming from the PV generation which tends to produce more power during HEC's peak hours. This graph is using data for January so the PV shift at 560 is slightly later than the same time period in ***Figure 19*** because the peak hour is 8:00am in the morning. The PV does not start producing at its peak until mid to late morning as indicated in the lower pink line on the graph at the peak at time 560 through 565. These hours coincide with 8:00am through 1:00pm on the 24rd day of the month. HEC's CP hour was 8:00am on that day when this data was recorded. Because there is no benefit at 8:00am, there is no benefit to HEC as there would be at a utility that might be able to run less peak generation.

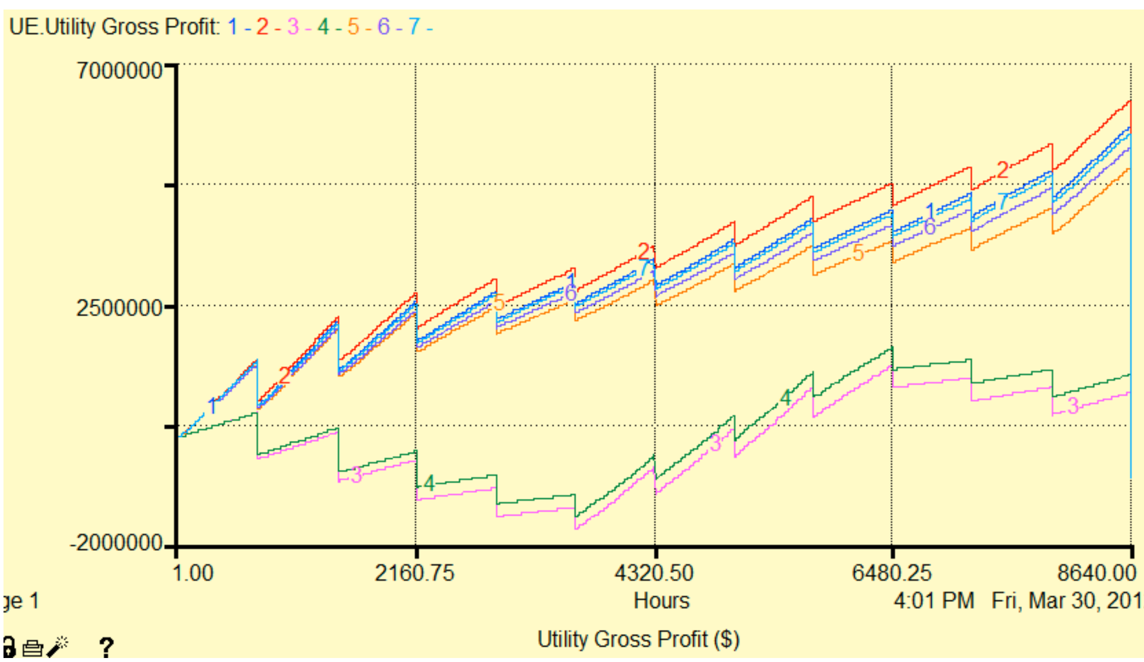


**Figure 21- Annual Gross Profit for Run 1 through 7**

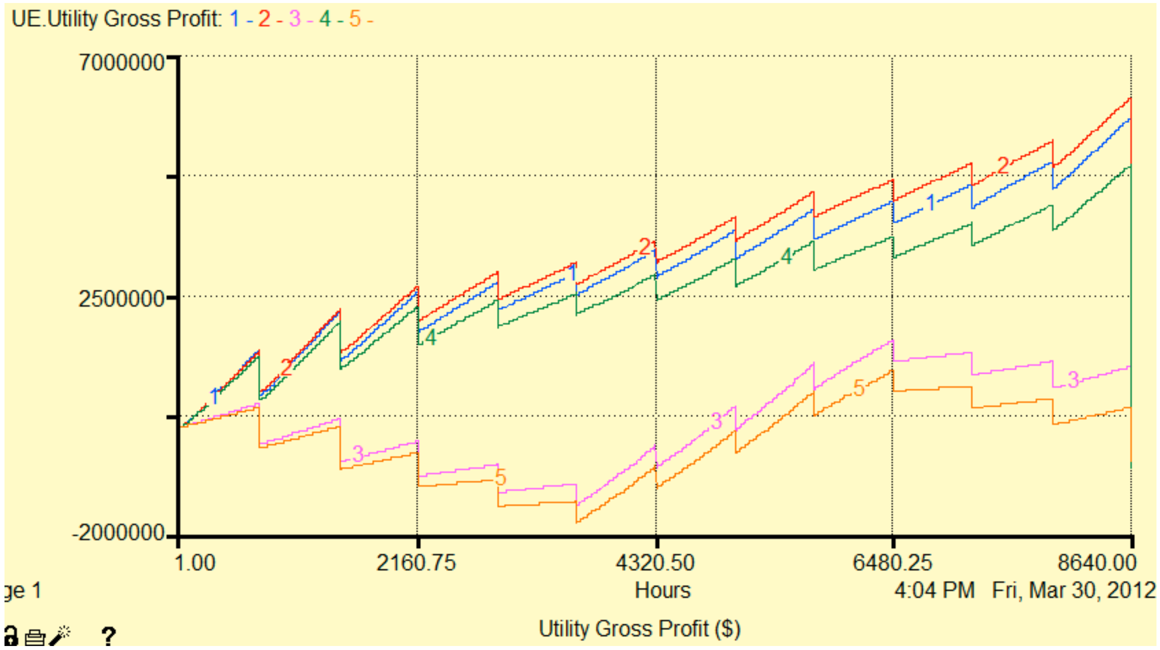


**Figure 22- Annual Gross Profit from Runs 1 and Runs 8 through 10 (2,3,4,5 on graph)**

The graphs in ***Figures 21 and 22*** show how HEC's profit accumulates over one year from monthly billings. The cause for the sawtooth shape in the graphs is the CP charge that significantly lowers profit as it is calculated at the end of each month. The profit climbs as sales accumulate and then when the CP demand charge is calculated at the beginning of the next month, the profit takes a drop. The lower data lines on both graphs are a result of the TOU rates being implemented. This drastic effect on profits was a surprise to HEC and to the author. The common wisdom is that TOU rates are detrimental to the customer but this shows differently. By analyzing the graphs, one can see that the rates are only good for HEC during the months June through September (hours 3600 through 6480). This effect can be accounted for by the larger load swings between peak and trough during the day for these months which allow HEC to earn more money at the peak rate than during other times of the year. In other words, HEC's daily load has a greater differential during the summer months. The percent difference between a peak and a trough during the summer months is greater than the winter months and much greater than the shoulder months of April, May, October, and November. The cause is most likely due to the increase use of air conditioning during the summer months which is a large portion of the total residential consumption during the summer.

**2. Which one of the combinations from question number 1 provides the best outcome for the profitability of the utility?**

As shown in ***Table 1***, Peak shifting without TOU rates (run number 2) will not affect the customer bill and give HEC the highest profitability increase. The model projects an increase in annual profit of $499,682 which represents an increase of 8.6%. This is due to the fact that the Coincident Peak demand charge is a significant portion of the utility's costs. Any reduction in Peak Demand will positively affect HEC's profitability. All other scenarios reduce this increase in profit by either reducing total sales of electricity or adding to the cost of the electricity sold by HEC.

**3. Which one of the combinations from question number 1 provides the best outcome for the saving of the most energy?**

The only strategy that actually reduces consumption, as discussed earlier and shown in *Figure 8,* is the EE strategy. The model run number 6 reduces Total Consumption the most. Run number 7 also reduces Total Consumption but not as much. The difference between # 6 and #7 is that the annual cost to implement the EE with all three implementations (run # 6) is more than the actual electricity cost savings based upon the current normal rate from HEC. Because of this cost, run #6 will not be considered viable. Run #7 provides the best outcome for saving the most energy and saves approximately 4,000,000 kWh which amounts to a 1.9% savings in consumed electricity.

The model provides for calculation of an '***adoption rate***' of the EE strategy based upon payback or return on investment. The curve determining the adoption rate is an S-shaped growth pattern that can vary between 6.5% and 83% with a beginning value of 16% of the whole residential customer class for HEC. The input range is based upon simple assumptions of early adoption and actual market potential. The values are meant for comparison purposes only and would have to be refined through market research to be more accurate. The calculation is updated at the end of every year so with HEC's lack of interest in multi-year analysis at this point, there was no further refinement made. However, the adoption rate would affect the extent of the potential savings from EE since the costs and savings have a linear relationship to number of adopters. In other words, a greater payback would entice a higher adoption rate and result in higher reductions in electricity consumption for the HEC residential market.

Another viewpoint can also be considered for this question. Based upon previous discussion of energy policy, our country's goal is to have electricity that is cheap, secure, and clean. If moving away from fossil-fuel based generation allows the policy goals to be met, then perhaps including electricity that comes from low-carbon or no-carbon sources can be considered a similar outcome to saving energy. Renewable energy by definition means that the source has no external inputs that deplete over time which is the reason society wants to 'save energy'. If this logic is sound then using the renewable DG sources can also contribute to 'saving energy' by not using a resource which can be depleted such as coal and natural gas. In this case, run number 10 shows the amount of electricity that is saved from EE and further saved from the amount that comes from FIT/DG that is based upon solar photovoltaics. This run indicates a total savings of approximately 8,800,000 kWh or 4.2% savings from run number 1 which represents 'business as usual'.

**4. What changes in the regulatory environment would improve the prospects for adopting these policies?**

Although HEC has no regulatory obligations, it is worthy to discuss how these strategies might affect regulatory policy for other utilities since the model is designed to serve other regions and utilities too. A Feed-in Tariff is normally a regulatory policy that could help HEC by lowering peak demand costs. A problem arises from the utility having to absorb the cost of these payments. FIT costs, the amount paid to the owners of the DG, would have to be recovered in some way to make it viable to the utilities. Some FIT plans have tried to recover costs through a tax vehicle but because taxes are political in nature, this method has a high failure rate [10]. Other FIT programs add a charge to the customers' bills. This extra charge could be split evenly across all customers as a fixed fee or it could be in the form of a per kWh rider. The application of the rider could protect certain types of customers such as intensive users of electricity like heavy industry or the rider could be restricted from low income customers [56]. The idea is to promote the DG that the FIT pays for but spread the new cost over a larger group. These rate policies would have to implemented through some form of regulatory body. For HEC, that would be its board of Commissioners. For other utilities such as Dominion Virginia Power, that authority would be the State Corporation Commission. FIT plans have been proposed at the local, state, and even federal level in the past but have had little success. Having a more flexible regulatory environment and progressive political climate would help FITs to be implemented.

Another recurring issue for DG and its implementation is the problem with power islanding. This problem occurs when a grid connected generating source such as solar PV continues to produce electricity after the rest of the grid as failed. This failure may come from storm damage or from utility work that requires removing power from distribution lines. The utility is concerned for the safety of its personnel as well as damage to its equipment from the errant PV source. With the advent of advanced power electronics, this threat is easily addressed. The problem lies with the regulatory and other oversight bodies that set standards for the industry. They have been slow to adopt changes that require these new capabilities. Currently, there are proposed changes to the two main standards in this area. They are sections of the IEEE 1547 and UL 1741 standards that address the issues associated with islanded power sources so DG can serve as standby power and continue to operate after the rest of the grid has failed. The bodies that adopt and enforce these standards need to move as quickly as possible to allow for the expansion of FIT/DG policies.

The last potential influence that regulators can have on these strategies is in the area of Energy Efficiency implementation. By allowing or requesting utilities to promote these measures, the regulators can accelerate their adoption. There are incentives that utilities have been given to implement EE policies with their customers. These come in form of tax breaks or credits and must be approved by legislative bodies which are certainly regulatory bodies. As with the FIT policy, a more progressive political climate will be necessary to widely implement these type of incentives. Otherwise, implementation of EE will take much longer as we wait for better product and cheaper costs.

## Conclusions

The concluding thoughts for this paper relate to the lessons learned and what further action might be taken to enhance the model and create a more useful tool for its intended user audience.

This paper is a culmination of hundreds of hours of research and modeling effort. The author is convinced that there is little disagreement about the challenges ahead for the electricity sector of the energy future in the U.S. The difficulty lies in the debate on how to solve them. Hopefully this thesis has addressed a portion of this debate and pointed to the utilities as being the key stakeholder in making meaningful changes. Through the simulations and conversation with HEC, this thesis has shown that there are possible strategies that can be implemented to help meet the new energy policy goals of cheap, secure, and clean.

Although this thesis represents a great deal of work, the project is still not complete. There are several areas that need further attention and study.

First and foremost, it is important to expand the time scale of this analysis to see multiyear behavior of the stakeholders. Many human behaviors cannot be studied on a scale of less than one year. The adoption of technology, the acceptance of new ideas, and the changing of how people behave all take years to measure. Although the longer term dynamics did not have immediate interest to the client, knowing or at least trying to understand possible outcomes of new strategies has to make sense to any business. Understanding the give and take of the regulatory process is also important to many of the potential users of this simulator. The current model is built to accept these new feedbacks and has already included some. However, due to the size and complex nature of the model it might be more practical to build a more aggregated (having less detail) model with just corporate and consumer behaviors accounted for and fewer measurable quantities such as the hourly load data used in this model. A more aggregated model would simplify the structure and show the new, long-term behaviors more clearly. It might not be necessary to see the interaction of the human behaviors with electricity metrics to the detailed perspective that this paper's model provides.

The other area where the model could be augmented and improved would be in the market dynamics of the pricing of the strategies. The stated goal of a FIT is to create a market for renewable energy so that economies of scale may be realized. Currently there is no feedback or other mechanism that deals with this dynamic. It may be instructive to include a mechanism to alter the capital cost of the strategy as market penetration grows. This effect has been well documented in the successful implementation of FIT's around the globe[10]. This mechanism could also be applied to the EE strategies. LED lighting prices have dropped significantly over the past 10 years because of greater market size which leads to new research and development for better efficiencies and greater market competition over time.

An area that needs further analysis is in the introduction of Time-of-Use rates for HEC. As stated earlier, it is common understanding that TOU is beneficial for utilities and difficult for homeowners to use for their advantage. In the case of HEC, the load data used in the model is the utility's total load that is rationed by customer class. It may be found that the load data shape (size of peaks and troughs) for all customer classes is different than the shape for just the residential class. In other words, the total loads may have different percent load changes during the day than the residential class. There are other customer classes that might contribute greatly to the overnight loads such as street lights or industrial users that would cover up the significant drops in residential troughs. If this is in fact the case, then the residential swings might be greater than modeled and the TOU rates would have a greater detrimental effect on the residential customer class leading to a better scenario for HEC.

The last comment is an invitation. There are many topics discussed in this paper and the author recognizes that the reader may have expertise that can shed additional light on the strategies and models developed here. If the reader has suggestions for model improvements, please contact the author, Brooks E Taylor at TaylorBE@Dukes.JMU.edu.

Hopefully you have gleaned some new insight or even have formed new ideas about the problems presented and their possible solutions. That, of course, is the major goal of the work.

Respectfully submitted,

Brooks E Taylor

## Appendix A - Exogenous Variables

| Module | Variable Name | Brief Description | Initial Value | units | Source |
|---|---|---|---|---|---|
| **Customer Economics (CE)** | CHP FIT | Price paid to DG owners for energy produced from CHP DG | $0.1359 | $/kWh | {Lamont, 2011, #1176} |
| | FIT Recovery Switch | Switch to turn on/off FIT recovery strategy | 0 | - | - |
| | FIT Rider | Price added to customer bills to recover the payout to FIT/DG owners | $0.0055 | $/kWh | author |
| | Fuel Adjustment | Adder to customer bills to adjust for market fluctuations of fuel used to generate electricity | $0.01723 | $/kWh | HEC |
| | HVAC Cost Per Watt Per Yr | Installation cost for HVAC EE strategy divided by number of years of expected service | $516.66 | $/watt/yr | {Lienau et al., 1995, #1171} |
| | Lighting Cost Per Watt Per Yr | Installation cost for lighting EE strategy divided by number of years of expected service | $0.2520 | $/watt/yr | {, #90731} |
| | Normal Rate Price | Base electricity price to residential customer | $0.07762 | $/kWh | HEC |
| | Solar FIT | Price paid to DG owners for energy from solar DG | $0.240 | $/kWh | {Lamont, 2011, #1176} |
| | TOU Rate Off Season | Table data for TOU rate structure in off-season | see model | $/KWh | {2012, #1164} |
| | TOU Rate Summer | Table data for TOU rate structure during summer months | see model | $/KWh | {2012, #1164} |

| Module | Variable Name | Brief Description | Initial Value | units | Source |
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| | TOU Rate Off Season | Table data for TOU rate structure in off-season | see model | $/KWh | {2012, #1164} |
| | TOU Rate Summer | Table data for TOU rate structure during summer months | see model | $/KWh | {2012, #1164} |

| | | | | | |
|---|---|---|---|---|---|
| | TOU Rate Winter | Table data for TOU rate structure during winter months | see model | $/KWh | {2012, #1164} |
| | TOU Switch | Switch to turn on/off HVAC EE strategy | 0 | - | - |
| | Water Htr Cost Per Watt Per Yr | Installation cost for water heater EE strategy divided by number of years of expected service | $128 | $/watt/yr | {Dubay et al., 2009, #1173} |
| | Wind FIT | Price paid to DG owners for energy produced from wind DG | $0.2083 | $/KWh | {Lamont, 2011, #1176} |
| | | | | | |
| **Customer Power (CP)** | CHP Capacity | Installed capacity of each CHP microturbine | 30 | KW | author |
| | CHP Percent Output | Average percent of annual output capacity of CHP strategy | 90 | % | {2010, #1179} |
| | CHP Switch | Switch to turn on/off HVAC EE strategy | 0 | - | - |
| | DG Switch | Switch to turn on/off HVAC EE strategy | 0 | - | - |
| | Pct CHP Adoption | Percent of residential customers that adopt Solar strategy | 0 | % | author |
| | Pct Solar Adoption | Percent of residential customers that adopt CHP strategy | 5 | % | author |
| | Pct Wind Adoption | Percent of residential customers that adopt Wind strategy | 0 | % | author |
| | Residential Customers | Total number of residential customers | 17,000 | accounts | HEC |

| | | | | | |
|---|---|---|---|---|---|
| | Solar Power Output | Hourly output from PV of typical day in Roanoke VA | see model | watts | {, #16375} |
| | Solar Switch | Switch to turn on/off HVAC EE strategy | 0 | - | - |
| | Wind Power Output | Hourly output from wind turbine of typical day in Roanoke VA | see model | watts | {, #21242}{2012, #1181} |
| | Wind Switch | Switch to turn on/off HVAC EE strategy | 0 | - | - |
| | | | | | |
| **Load Data (LD)** | April Hourly Demand Curve | Total load date representative of spring shoulder months | see model | KW | HEC |
| | Amount Shifted | Amount of Power that can be shifted at once for peak shifting | 5000 | KW | author |
| | Avg Percent Lighting | Table of data for hourly percentages of the residential load that is from lighting | 14% for hours 1-24 | % | {, #34861} |
| | Effic Delay | Number of years before EE strategy starts | 0 | years | - |
| | Efficiency Switch | Switch to turn on/off ALL EE strategies | 0 | - | - |
| | HVAC Efficiency Improvement | Percent reduction of HVAC load due to efficiency strategy | 31 | % | {Lienau et al., 1995, #1171} |
| | HVAC Switch | Switch to turn on/off HVAC EE strategy | 0 | - | - |
| | Jan Hourly Demand Curve | Total load date representative of winter months | see model | KW | HEC |

| | | | | | |
|---|---|---|---|---|---|
| | June Hourly Demand Curve | Total load date representative of summer months | see model | KW | HEC |
| | Lighting Efficiency Improvement | Percent reduction of lighting load due to efficiency strategy | 88 | % | {, #90731} |
| | Lighting Switch | Switch to turn on/off Lighting EE strategy | 0 | - | - |
| | October Hourly Demand Curve | Total load date representative of fall shoulder months | see model | KW | HEC |
| | Peak Range % | Percent of a peak demand running average that causes the stored capacity to be released | 0 | % | author |
| | Percent HVAC | Percentage of the residential load that is due to HVAC equipment | 49 | % | {2011, #1174} |
| | Percent Water Htr | Percentage of the residential load that is due to the electric water heater | 20 | % | {2011, #1174} |
| | Residential % | Table data that provide the monthly percentage of the total utility load that is residential | see model | % | HEC |
| | Roundtrip Efficiency | Overall efficiency of Peak Storage after it is stored and returned to use | 100 | % | author |
| | Shifted Load Switch | Switch to turn on/off HVAC EE strategy | 0 | - | - |
| | Storage Capacity kWh | Total storage capacity available for Peak Shifting | 20,000 | KWh | author |

| | | | | | |
|---|---|---|---|---|---|
| | Trough Range % | Percent of trough running average that causes the stored capacity to be charged | 20 | % | author |
| | Water Htr Efficiency Improvement | Percent reduction of water heater load due to efficiency strategy | 59 | % | {Dubay et al., 2009, #1173} |
| | Water Htr Switch | Switch to turn on/off HVAC EE strategy | 0 | - | - |
| | | | | | |
| **Strategy Costs (SC)** | CHP Install Cost | Total Installed Cost of a CHP microturbine | $3,000 | $/KW/yr | {McAvoy, 2011, #1188; Pierce P E, 2005, #1187} |
| | CHP System Operating Costs | Annual Costs to operate and maintain a microturbine | $0.0250 | $/KWh | {McAvoy, 2011, #1188; Pierce P E, 2005, #1187} |
| | Shifted Load Storage Costs | Installed costs of the Peak Shifting Strategy | $17.09 | $/KW/yr | author |
| | Solar System Costs | Installed costs for PV solar strategy | $0.24 | $/watt/yr | {Barbose et al., 2011, #1185} |
| | Wind System Costs | Installed costs for wind turbine system | $1,000 | $/yr | {, #34634} |
| | | | | | |
| **Regulatory (Reg)** | Allowed Gross Profit | Comparative Value for regulating utility profit | 30 | % | author |
| | | | | | |
| **Utility Economics (UE)** | CP Price | Contract power purchase price | $0.04 | $/KWh | HEC |

## Appendix B - Model Variables and Equations

```
Accum_Effic_Savings(t) = Accum_Effic_Savings(t - dt) + (Cost_Reduction_From_Effic - Annual_Reset_6) * dt
INIT Accum_Effic_Savings = 0

INFLOWS:
    Cost_Reduction_From_Effic = Actual_Electricity_Rate*LD.Efficiency_Load_Reduction
OUTFLOWS:
    Annual_Reset_6 = IF (MOD(TIME,8641)=0) THEN Accum_Effic_Savings ELSE 0
Accumulated_Earnings(t) = Accumulated_Earnings(t - dt) + (Annual_Accounting) * dt
INIT Accumulated_Earnings = 0

INFLOWS:
    Annual_Accounting = IF (MOD(TIME,8640)=0) THEN Utility_Gross_Profit ELSE 0
Accumulated_Energy_Sales(t) = Accumulated_Energy_Sales(t - dt) + (Annual_Reset_4) * dt
INIT Accumulated_Energy_Sales = 0

INFLOWS:
    Annual_Reset_4 = IF (MOD(TIME,8640)=0) THEN Past_Annual_Sales ELSE 0
Actual_Adjusted_Monthly_Peak_Demand_Picker(t) = Actual_Adjusted_Monthly_Peak_Demand_Picker(t - dt) + (Store -
Erase) * dt
INIT Actual_Adjusted_Monthly_Peak_Demand_Picker = 0

INFLOWS:
    Store = IF (MOD(TIME,720)=0) THEN 0 ELSE (IF (LD.Customer_Consumption_Data>
    Actual_Nonadjusted_Peak_Demand_Picker) THEN Power_Flow_from_Utility ELSE 0)
OUTFLOWS:
    Erase = IF (MOD(TIME,720)=0) THEN Actual_Adjusted_Monthly_Peak_Demand_Picker ELSE (IF
    (LD.Customer_Consumption_Data>Actual_Nonadjusted_Peak_Demand_Picker) THEN
    Actual_Adjusted_Monthly_Peak_Demand_Picker ELSE 0)

Actual_Nonadjusted_Peak_Demand_Picker(t) = Actual_Nonadjusted_Peak_Demand_Picker(t - dt) + (Store_2 - Erase_2)
* dt
INIT Actual_Nonadjusted_Peak_Demand_Picker = 0

INFLOWS:
```

```
Store_2 = IF (MOD(TIME,720)=0) THEN 0 ELSE (IF (LD.Customer_Consumption_Data>
    Actual_Nonadjusted_Peak_Demand_Picker) THEN LD.Customer_Consumption_Data ELSE 0)
OUTFLOWS:
  Erase_2 = IF (MOD(TIME,720)=0) THEN Actual_Nonadjusted_Peak_Demand_Picker ELSE (IF
    (LD.Customer_Consumption_Data>Actual_Nonadjusted_Peak_Demand_Picker) THEN
    Actual_Nonadjusted_Peak_Demand_Picker ELSE 0)
Annual_Energy_Sales(t) = Annual_Energy_Sales(t - dt) + (Hourly_Electricity_Sales - Annual_Reset_3) * dt
INIT Annual_Energy_Sales = .1
INFLOWS:
  Hourly_Electricity_Sales = Actual_Electricity_Rate*(CP.Power_Flow_from_Utility+
    CP.Distributed_Generation_Rate)
OUTFLOWS:
  Annual_Reset_3 = IF (MOD(TIME,8640)=0) THEN Annual_Energy_Sales ELSE 0
Annual_Utility_Energy_Costs(t) = Annual_Utility_Energy_Costs(t - dt) + (Contract_Power + Peak_Diesel_Cost +
Peak_Turbine_Cost + Monthly_Coincident_Peak_Charge + DG_Costs - Annual_Reset) * dt
INIT Annual_Utility_Energy_Costs = .1
INFLOWS:
  Contract_Power = CP_Price*UP.Contract_Power_Supply
  Peak_Diesel_Cost = PD_Price*UP.Diesel_Peak_Production
  Peak_Turbine_Cost = PT_Price*UP.Peak_Turbine_Production
  Monthly_Coincident_Peak_Charge = IF (MOD(TIME,720)=0) THEN
    ((CP.Actual_Adjusted_Monthly_Peak_Demand_Picker*Coincident_Peak_Demand_Price)+
    Fixed_Cost_Adjustment_Calculation) ELSE 0
  DG_Costs = CE.Distributed_Generation_Revenue
OUTFLOWS:
  Annual_Reset = IF (MOD(TIME,8640)=0) THEN Annual_Utility_Energy_Costs ELSE 0
Customer_Costs_for_Effic(t) = Customer_Costs_for_Effic(t - dt) + (Customer_Costs_per_Year_for_Strategies -
Annual_Reset_5) * dt
INIT Customer_Costs_for_Effic = 0
```

```
INFLOWS:
    Customer_Costs_per_Year_for_Strategies = IF (MOD(TIME,8640)=0) THEN (LD.Efficiency_Control*
    ((((Water_Htr_Cost_Per_House_Per_Yr*LD.Wtr_Htr_Switch)+(HVAC_Cost_Per_House_Per_Yr*
    LD.HVAC_Switch))*CP.Residential_Customers)+(Lighting_Cost_Per_Watt_Per_Yr*LD.Lighting_Loads*1000))*
    LD.Adoption_Rate/100) ELSE 0
OUTFLOWS:
    Annual_Reset_5 = IF (MOD(TIME,8641)=0) THEN Customer_Costs_for_Effic ELSE 0
Customer_Revenue_from_DG(t) = Customer_Revenue_from_DG(t - dt) + (Distributed_Generation_Revenue) * dt
INIT Customer_Revenue_from_DG = 0
INFLOWS:
    Distributed_Generation_Revenue = CP.DG_Switch*((CP.CHP_Gen*LOOKUP(CHP_FIT,INT(TIME/8640)))+
    (CP.Wind_Gen*LOOKUP(Wind_FIT,INT(TIME/8640)))+(CP.Solar_Gen*LOOKUP(Solar_FIT,INT(TIME/8640))))
Daily_Peak_Demand_Picker(t) = Daily_Peak_Demand_Picker(t - dt) + (Store_2 - Push_a_Peak - Erase_2) * dt
INIT Daily_Peak_Demand_Picker = 0
INFLOWS:
    Store_2 = IF (MOD(TIME,720)=0) THEN 0 ELSE (IF (Customer_Consumption_Data>Daily_Peak_Demand_Picker)
    THEN Customer_Consumption_Data ELSE 0)
OUTFLOWS:
    Push_a_Peak = IF (MOD(TIME,24)=0) THEN Daily_Peak_Demand_Picker ELSE 0
    Erase_2 = IF (Customer_Consumption_Data>Daily_Peak_Demand_Picker) THEN Daily_Peak_Demand_Picker ELSE 0
Daily_Trough_Picker(t) = Daily_Trough_Picker(t - dt) + (Store_3 - Push_a_Trough - Erase_3) * dt
INIT Daily_Trough_Picker = Customer_Consumption_Data
INFLOWS:
    Store_3 = IF (MOD(TIME,24)=0) THEN Customer_Consumption_Data ELSE (IF (Customer_Consumption_Data<
    Daily_Trough_Picker) THEN Customer_Consumption_Data ELSE 0)
OUTFLOWS:
    Push_a_Trough = IF (MOD(TIME,24)=0) THEN Daily_Trough_Picker ELSE 0
    Erase_3 = IF (MOD(TIME,24)=0) THEN 0 ELSE (IF (Customer_Consumption_Data<Daily_Trough_Picker) THEN
    Daily_Trough_Picker ELSE 0)
```

```
Past_Annual_Cost(t) = Past_Annual_Cost(t - dt) + (Annual_Reset - Annual_Reset_II) * dt
INIT Past_Annual_Cost = 0
 INFLOWS:
   Annual_Reset = IF (MOD(TIME,8640)=0) THEN Annual_Utility_Energy_Costs ELSE 0
 OUTFLOWS:
   Annual_Reset_II = IF (MOD(TIME,8640)=0) THEN Past_Annual_Cost ELSE 0
Past_Annual_Sales(t) = Past_Annual_Sales(t - dt) + (Annual_Reset_3 - Annual_Reset_4) * dt
INIT Past_Annual_Sales = .001
 INFLOWS:
   Annual_Reset_3 = IF (MOD(TIME,8640)=0) THEN Annual_Energy_Sales ELSE 0
 OUTFLOWS:
   Annual_Reset_4 = IF (MOD(TIME,8640)=0) THEN Past_Annual_Sales ELSE 0
Seven_Days_of_Peak(t) = Seven_Days_of_Peak(t - dt) + (Push_a_Peak - Drop_a_Peak) * dt
INIT Seven_Days_of_Peak = 0
 TRANSIT TIME = 168
 INFLOW LIMIT = ∞
 CAPACITY = ∞

 INFLOWS:
   Push_a_Peak = IF (MOD(TIME,24)=0) THEN Daily_Peak_Demand_Picker ELSE 0
 OUTFLOWS:
   Drop_a_Peak = CONVEYOR OUTFLOW
Seven_Days_of_Troughs(t) = Seven_Days_of_Troughs(t - dt) + (Push_a_Trough - Drop_a_Trough) * dt
INIT Seven_Days_of_Troughs = 0
 TRANSIT TIME = 168
 INFLOW LIMIT = ∞
 CAPACITY = ∞

 INFLOWS:
   Push_a_Trough = IF (MOD(TIME,24)=0) THEN Daily_Trough_Picker ELSE 0
 OUTFLOWS:
```

```
    Drop_a_Trough = CONVEYOR OUTFLOW
Shifted_Load_Storage(t) = Shifted_Load_Storage(t - dt) + (- ToFrom_Storage - Storage_Loss) * dt
INIT Shifted_Load_Storage = 0

 OUTFLOWS:
    ToFrom_Storage = IF (Shifted_Load_Switch=1) THEN (IF(Customer_Consumption_Data<((1+(Trough_Range_%/
    100))*Seven_Days_of_Troughs/7) AND (Shifted_Load_Storage<Storage_Capacity_kwh)) THEN (-1*
    Amount_Shifted) ELSE IF (Customer_Consumption_Data>((1-(Peak_Range_%/100))*Seven_Days_of_Peak/7))
    THEN (Amount_Shifted*(Roundtrip_Efficiency/100)) ELSE 0) ELSE 0

    Storage_Loss = If (ToFrom_Storage>0) THEN (Amount_Shifted-ToFrom_Storage) ELSE 0
Strategy_Investment(t) = Strategy_Investment(t - dt) + (Strategy_Costs - Strategy_Savings) * dt
INIT Strategy_Investment = 0

 INFLOWS:
    Strategy_Costs = IF (MOD(TIME,8640)=0) THEN (SC.Utility_Costs_Per_Year_For_Strategies) ELSE 0
 OUTFLOWS:
    Strategy_Savings = 0
Total_Consumption_kwh(t) = Total_Consumption_kwh(t - dt) + (Power_Flow_from_Utility + LD.ToFrom_Storage +
Distributed_Generation_Rate) * dt
INIT Total_Consumption_kwh = 0

 INFLOWS:
    Power_Flow_from_Utility = LD.Customer_Consumption_Data-LD.ToFrom_Storage-Distributed_Generation_Rate
    LD.ToFrom_Storage = IF (Shifted_Load_Switch=1) THEN (IF(Customer_Consumption_Data<((1+(Trough_Range_%/
    100))*Seven_Days_of_Troughs/7) AND (Shifted_Load_Storage<Storage_Capacity_kwh)) THEN (-1*
    Amount_Shifted) ELSE IF (Customer_Consumption_Data>((1-(Peak_Range_%/100))*Seven_Days_of_Peak/7))
    THEN (Amount_Shifted*(Roundtrip_Efficiency/100)) ELSE 0) ELSE 0

    Distributed_Generation_Rate = Total_DG_Rate
Total_Demand(t) = Total_Demand(t - dt) + (Contract_Power_Supply + Diesel_Peak_Production +
Peak_Turbine_Production - Consumption_Flow) * dt
INIT Total_Demand = 0

 INFLOWS:
```

Contract_Power_Supply = Consumption_Flow-Diesel_Peak_Production-Peak_Turbine_Production

Diesel_Peak_Production = LOOKUP(PD_Schedule,MOD(TIME,24))

Peak_Turbine_Production = LOOKUP(PT_Schedule,MOD(TIME,24))

OUTFLOWS:

Consumption_Flow = CP.Power_Flow_from_Utility

Total_DG_Produced(t) = Total_DG_Produced(t - dt) + (- Distributed_Generation_Rate) * dt
INIT Total_DG_Produced = 0

OUTFLOWS:

Distributed_Generation_Rate = Total_DG_Rate

UNATTACHED:

Efficiency_Load_Reduction = Efficiency_Control*(((Lighting_Effic+HVAC_Effic+Appliance_Effic))*(Adoption_Rate/100))

Actual_Electricity_Rate = IF (TOU_Switch=0) THEN (Normal_Rate_Price+Fuel_Adjustment+Rider) ELSE IF (LD.Month>=1 AND LD.Month<=3) THEN (LOOKUP(TOU_Rate_Winter,MOD(TIME,24)+Fuel_Adjustment+Rider)) ELSE IF (LD.Month>=4 AND LD.Month<=5) THEN (LOOKUP(TOU_Rate_Off_Season,MOD(TIME,24)+Fuel_Adjustment+Rider)) ELSE IF (LD.Month>=6 AND LD.Month<=9) THEN (LOOKUP(TOU_Rate_Summer,MOD(TIME,24)+Fuel_Adjustment+Rider)) ELSE IF (LD.Month=10) THEN (LOOKUP(TOU_Rate_Off_Season,MOD(TIME,24)+Fuel_Adjustment+Rider)) ELSE (LOOKUP(TOU_Rate_Winter,MOD(TIME,24)+Fuel_Adjustment+Rider))

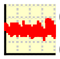
Adoption_Rate = GRAPH(CE.Effic_Payback)
(0.00, 6.50), (0.2, 7.00), (0.4, 7.50), (0.6, 9.00), (0.8, 11.5), (1.00, 15.5), (1.20, 29.5), (1.40, 57.5), (1.60, 69.0), (1.80, 78.5), (2.00, 83.5)

Allowed_Gross_Profit = 30

Amount_Shifted = 5000

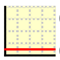
Appliance_Effic = Wtr_Htr_Loads*Water_Htr_Efficiency_Improvement/100

April_Hourly_Demand_Curve = GRAPH(TIME)



(0.00, 76.0), (1.00, 76.0), (2.00, 74.8), (3.00, 73.7), (4.00, 73.5), (5.00, 77.7), (6.00, 81.0), (7.00, 88.3), (8.00, 92.7), (9.00, 95.7), (10.0, 95.7), (11.0, 91.9), (12.0, 93.4), (13.0, 92.0), (14.0, 91.4), (15.0, 89.7), (16.0, 87.0), (17.0, 85.1), (18.0, 84.4), (19.0, 83.9), (20.0, 89.7), (21.0, 88.4), (22.0, 84.2), (23.0, 78.8), (24.0, 73.2), (25.0, 70.8), (26.0, 70.0), (27.0, 67.5), (28.0, 68.4), (29.0, 68.6), (30.0, 71.3), (31.0, 74.4), (32.0, 76.2), (33.0, 76.2), (34.0, 78.3), (35.0, 80.2), (36.0, 78.7), (37.0, 79.2), (38.0, 78.0), (39.0, 76.2), (40.0, 76.3), (41.0, 77.9), (42.0, 78.4), (43.0, 77.2), (44.0, 83.6), (45.0, 80.2), (46.0, 76.1), (47.0, 72.1), (48.0, 68.3), (49.0, 65.7), (50.0, 63.9), (51.0, 63.4), (52.0, 63.2)...

Avg_Percent_Lighting = GRAPH(TIME)



(0.00, 14.0), (1.00, 14.0), (2.00, 14.0), (3.00, 14.0), (4.00, 14.0), (5.00, 14.0), (6.00, 14.0), (7.00, 14.0), (8.00, 14.0), (9.00, 14.0), (10.0, 14.0), (11.0, 14.0), (12.0, 14.0), (13.0, 14.0), (14.0, 14.0), (15.0, 14.0), (16.0, 14.0), (17.0, 14.0), (18.0, 14.0), (19.0, 14.0), (20.0, 14.0), (21.0, 14.0), (22.0, 14.0), (23.0, 14.0)

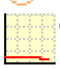
CHP_Capacity = 30.0

CHP_Gen = CHP_Switch*LOOKUP(CHP_Percent_Output,MOD(TIME,24))*(CHP_Capacity/100)*Residential_Customers*(Pct_CHP_Adoption/100)

CHP_Install_Cost = 9000.0

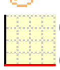
CHP_Switch = 0

CHP_FIT = GRAPH(TIME)



(0.00, 0.136), (5.00, 0.136), (10.0, 0.136), (15.0, 0.136), (20.0, 0.1), (25.0, 0.1)

CHP_Percent_Output = GRAPH(TIME)



(0.00, 90.0), (1.00, 90.0), (2.00, 90.0), (3.00, 90.0), (4.00, 90.0), (5.00, 90.0), (6.00, 90.0), (7.00, 90.0), (8.00, 90.0), (9.00, 90.0), (10.0, 90.0), (11.0, 90.0), (12.0, 90.0), (13.0, 90.0), (14.0, 90.0), (15.0, 90.0), (16.0, 90.0), (17.0, 90.0), (18.0, 90.0), (19.0, 90.0), (20.0, 90.0), (21.0, 90.0), (22.0, 90.0), (23.0, 90.0)

CHP_System_Operating_Costs = 0.035

Coincident_Peak_Demand_Price = 16.607

```
CP_Price = 0.036
Customer_Consumption_Data = Typical_Residential_Consumption-Efficiency_Load_Reduction
Determine_Season = (IF (1<=Month) AND (Month<=3) THEN LOOKUP(Jan_Hourly_Demand_Curve,MOD(TIME,720)) ELSE IF
(4<=Month) AND (Month<=5) THEN LOOKUP(April_Hourly_Demand_Curve,MOD(TIME,720)) ELSE IF (6<=Month) AND
(Month<=8) THEN LOOKUP(June_Hourly_Demand_Curve,MOD(TIME,720)) ELSE IF (9<=Month) AND (Month<=11) THEN
LOOKUP(October_Hourly_Demand_Curve,MOD(TIME,720)) ELSE LOOKUP(Jan_Hourly_Demand_Curve,MOD(TIME,720)))*
kwperMW

DG_Switch = 0
Effic_Delay = 0
Effic_Payback = IF(Customer_Costs_for_Effic<=0) THEN 1 ELSE (Accum_Effic_Savings/Customer_Costs_for_Effic)
Efficiency_Control = STEP(Efficiency_Switch,Effic_Delay*8640)
Efficiency_Switch = 0
FIT_Recovery_Switch = 0
FIT_Rider = .0055
Fixed_Cost_Adjustment = 2.0E+5
Fixed_Cost_Adjustment_Calculation = Fixed_Cost_Adjustment*(LOOKUP(LD.Residential_%,INT(TIME/720))/100)
Fuel_Adjustment = 0.01723
Hour_of_the_Day = MOD(TIME,24)
HVAC_Cost_Per_House_Per_Yr = 516.66
HVAC_Effic = HVAC_Loads*HVAC_Efficiency_Improvement/100
HVAC_Efficiency_Improvement = 31.0
HVAC_Loads = HVAC_Switch*Typical_Residential_Consumption*Percent_HVAC/100
HVAC_Switch = 0
```

Jan_Hourly_Demand_Curve = GRAPH(TIME)
(0.00, 60.4), (1.00, 59.4), (2.00, 58.8), (3.00, 58.1), (4.00, 57.9), (5.00, 58.6), (6.00, 60.8), (7.00, 62.7), (8.00, 60.7), (9.00, 63.5), (10.0, 65.3), (11.0, 67.0), (12.0, 66.6), (13.0, 66.0), (14.0, 67.3), (15.0, 66.9), (16.0, 66.8), (17.0, 71.1), (18.0, 73.7), (19.0, 71.8), (20.0, 70.5), (21.0, 68.4), (22.0, 65.0), (23.0, 61.3), (24.0, 57.1), (25.0, 55.0), (26.0, 52.5), (27.0, 52.0), (28.0, 51.7), (29.0, 55.0), (30.0, 57.6), (31.0, 60.1), (32.0, 62.6), (33.0, 64.6), (34.0, 66.6), (35.0, 65.8), (36.0, 67.6), (37.0, 69.3), (38.0, 68.1), (39.0, 68.8), (40.0, 71.2), (41.0, 75.3), (42.0, 83.1), (43.0, 83.1), (44.0, 84.0), (45.0, 82.8), (46.0, 81.8), (47.0, 77.1), (48.0, 76.1), (49.0, 75.3), (50.0, 75.6), (51.0, 76.6), (52.0, 79.8)...

June_Hourly_Demand_Curve = GRAPH(TIME)
(0.00, 71.1), (1.00, 66.7), (2.00, 63.5), (3.00, 62.5), (4.00, 61.6), (5.00, 65.8), (6.00, 71.3), (7.00, 79.5), (8.00, 88.2), (9.00, 97.1), (10.0, 104), (11.0, 108), (12.0, 106), (13.0, 105), (14.0, 110), (15.0, 110), (16.0, 110), (17.0, 109), (18.0, 107), (19.0, 102), (20.0, 99.8), (21.0, 101), (22.0, 93.2), (23.0, 85.7), (24.0, 75.7), (25.0, 69.1), (26.0, 66.4), (27.0, 65.0), (28.0, 64.6), (29.0, 67.9), (30.0, 72.0), (31.0, 78.9), (32.0, 87.7), (33.0, 94.8), (34.0, 102), (35.0, 107), (36.0, 110), (37.0, 112), (38.0, 113), (39.0, 113), (40.0, 115), (41.0, 112), (42.0, 107), (43.0, 108), (44.0, 104), (45.0, 105), (46.0, 97.6), (47.0, 87.8), (48.0, 79.7), (49.0, 74.7), (50.0, 70.6), (51.0, 69.1), (52.0, 68.8)...

kwperMW = 1000

Lighting_Cost_Per_Watt_Per_Yr = 0.252

Lighting_Efficiency_Improvement = 88.0

Lighting_Loads = Lighting_Switch*Typical_Residential_Consumption*(Avg_Percent_Lighting/100)*(Pct_Lights_Converted/100)

Lighting_Switch = 0

Lighting_Effic = Lighting_Loads*Lighting_Efficiency_Improvement/100

Month = INT((MOD(TIME,8640))/720)+1

Normal_Rate_Price = 0.07762

October_Hourly_Demand_Curve = GRAPH(TIME)
(0.00, 66.0), (1.00, 63.3), (2.00, 59.3), (3.00, 57.3), (4.00, 57.7), (5.00, 62.1), (6.00, 68.2), (7.00, 76.3), (8.00, 79.4), (9.00, 82.4), (10.0, 86.0), (11.0, 87.9), (12.0, 88.1), (13.0, 83.6), (14.0, 83.4), (15.0, 85.2), (16.0, 86.3), (17.0, 84.5), (18.0, 82.5), (19.0, 85.8), (20.0, 85.7), (21.0, 81.3), (22.0, 74.1), (23.0, 68.5), (24.0, 62.0), (25.0, 58.8), (26.0, 56.1), (27.0, 55.1), (28.0, 53.7), (29.0, 55.7), (30.0, 58.0), (31.0, 59.8), (32.0, 61.2), (33.0, 67.2), (34.0, 70.8), (35.0, 73.8), (36.0, 77.9), (37.0, 81.0), (38.0, 83.0), (39.0, 85.7), (40.0, 86.1), (41.0, 87.8), (42.0, 86.9), (43.0, 90.7), (44.0, 90.1), (45.0, 85.8), (46.0, 80.5), (47.0, 74.6), (48.0, 68.9), (49.0, 64.3), (50.0, 61.6), (51.0, 60.1), (52.0, 60.6)...

Pct_CHP_Adoption = 0
Pct_Lights_Converted = 100
Pct_Solar_Adoption = 0
Pct_Wind_Adoption = 0
PD_Schedule = GRAPH(TIME)
(0.00, 0.1), (1.00, 0.1), (2.00, 0.1), (3.00, 0.1), (4.00, 0.1), (5.00, 0.1), (6.00, 0.1), (7.00, 0.1), (8.00, 0.1), (9.00, 0.1), (10.0, 0.1), (11.0, 0.1), (12.0, 0.1), (13.0, 0.1), (14.0, 0.1), (15.0, 0.1), (16.0, 0.1), (17.0, 0.1), (18.0, 0.1), (19.0, 0.1), (20.0, 0.1), (21.0, 0.1), (22.0, 0.1), (23.0, 0.1)

PD_Price = 0.18
Peak_Range_% = 0
Percent_HVAC = 49.0
Percent_Water_Htr = 20.0
PT_Schedule = GRAPH(TIME)
(0.00, 0.1), (1.00, 0.1), (2.00, 0.1), (3.00, 0.1), (4.00, 0.1), (5.00, 0.1), (6.00, 0.1), (7.00, 0.1), (8.00, 0.1), (9.00, 0.1), (10.0, 0.1), (11.0, 0.1), (12.0, 0.1), (13.0, 0.1), (14.0, 0.1), (15.0, 0.1), (16.0, 0.1), (17.0, 0.1), (18.0, 0.1), (19.0, 0.1), (20.0, 0.1), (21.0, 0.1), (22.0, 0.1), (23.0, 0.1)

PT_Price = 0.031
Regulator_Adjustment = Regulatory_Review_Metric-Allowed_Gross_Profit
Regulatory_Review_Metric = ((CE.Past_Annual_Sales-UE.Past_Annual_Cost)/CE.Past_Annual_Sales+1)*100
Residential_Customers = 17000

Residential_% = GRAPH(TIME)
(0.00, 35.6), (1.00, 38.5), (2.00, 31.6), (3.00, 29.0), (4.00, 22.4), (5.00, 22.3), (6.00, 23.0), (7.00, 24.9), (8.00, 22.4), (9.00, 23.1), (10.0, 26.7), (11.0, 32.7)

Rider = FIT_Recovery_Switch*FIT_Rider
Roundtrip_Efficiency = 100
Sales_Trend = Annual_Energy_Sales-Past_Annual_Sales
Shifted_Load_Switch = 0
Shifted_Load_Storage_Costs = 17.09
Solar_FIT = GRAPH(TIME)
(0.00, 0.24), (5.00, 0.24), (10.0, 0.24), (15.0, 0.24), (20.0, 0.24), (25.0, 0.1)

Solar_Gen = Solar_Switch*(LOOKUP(Solar_Power_Output,MOD(TIME,24))/1000)*Residential_Customers*(Pct_Solar_Adoption/100)

Solar_Power_Output = GRAPH(TIME)
(0.00, 0.00), (1.00, 0.00), (2.00, 0.00), (3.00, 0.00), (4.00, 0.00), (5.00, 0.00822), (6.00, 8.95), (7.00, 351), (8.00, 981), (9.00, 1577), (10.0, 1988), (11.0, 2221), (12.0, 2209), (13.0, 2156), (14.0, 1879), (15.0, 1373), (16.0, 755), (17.0, 189), (18.0, 2.21), (19.0, 0.00), (20.0, 0.00), (21.0, 0.00), (22.0, 0.00), (23.0, 0.00)

Solar_Switch = 0
Solar_System_Costs = 0.24
Storage_Capacity_kwh = 25000
Total_DG_Rate = DG_Switch*(CHP_Gen+Solar_Gen+Wind_Gen)

TOU_Rate_Summer = GRAPH(TIME)
(0.00, 0.05), (1.00, 0.05), (2.00, 0.05), (3.00, 0.05), (4.00, 0.05), (5.00, 0.05), (6.00, 0.05), (7.00, 0.05), (8.00, 0.05), (9.00, 0.05), (10.0, 0.05), (11.0, 0.05), (12.0, 0.05), (13.0, 0.25), (14.0, 0.25), (15.0, 0.25), (16.0, 0.25), (17.0, 0.25), (18.0, 0.25), (19.0, 0.25), (20.0, 0.05), (21.0, 0.05), (22.0, 0.05), (23.0, 0.05)

TOU_Switch = 1

TOU_Rate_Off_Season = GRAPH(TIME)
(1.00, 0.05), (1.96, 0.05), (2.91, 0.05), (3.87, 0.05), (4.83, 0.05), (5.78, 0.05), (6.74, 0.05), (7.70, 0.05), (8.65, 0.05), (9.61, 0.05), (10.6, 0.05), (11.5, 0.05), (12.5, 0.05), (13.4, 0.05), (14.4, 0.05), (15.3, 0.05), (16.3, 0.05), (17.3, 0.05), (18.2, 0.05), (19.2, 0.05), (20.1, 0.05), (21.1, 0.05), (22.0, 0.05), (23.0, 0.05)

TOU_Rate_Winter = GRAPH(TIME)
(0.00, 0.05), (1.00, 0.05), (2.00, 0.05), (3.00, 0.05), (4.00, 0.05), (5.00, 0.07), (6.00, 0.07), (7.00, 0.07), (8.00, 0.07), (9.00, 0.07), (10.0, 0.05), (11.0, 0.05), (12.0, 0.05), (13.0, 0.05), (14.0, 0.05), (15.0, 0.05), (16.0, 0.05), (17.0, 0.05), (18.0, 0.05), (19.0, 0.05), (20.0, 0.05), (21.0, 0.05), (22.0, 0.05), (23.0, 0.05)

Trough_Range_% = 15

Typical_Residential_Consumption = (Determine_Season*(LOOKUP(Residential_%,INT((MOD(TIME,8640))/720))/100))

Utility_Gross_Profit = CE.Annual_Energy_Sales-Annual_Utility_Energy_Costs

Utility_Costs_Per_Year_For_Strategies = CP.DG_Switch*(CP.CHP_Switch*((CHP_Install_Cost*CP.Residential_Customers*(CP.Pct_CHP_Adoption/100))+(CP.CHP_Gen*CHP_System_Operating_Costs))+(CP.Solar_Switch*Solar_System_Costs*4500*CP.Residential_Customers*(CP.Pct_Solar_Adoption/100))+(CP.Wind_Switch*Wind_System_Costs*CP.Residential_Customers*(CP.Pct_Wind_Adoption/100)))+(LD.Shifted_Load_Switch*LD.Storage_Capacity_kwh*Shifted_Load_Storage_Costs)

Water_Htr_Cost_Per_House_Per_Yr = 128.0

Water_Htr_Efficiency_Improvement = 59.0

watts_per_kw = 1000

Wind_Capacity = 10

```
Wind_FIT = GRAPH(TIME)
(0.00, 0.208), (5.00, 0.208), (10.0, 0.208), (15.0, 0.208), (20.0, 0.208), (25.0, 0.1)

Wind_Gen = Wind_Switch*(LOOKUP(Wind_Power_Output,MOD(TIME,24))/1000)*Residential_Customers*
(Pct_Wind_Adoption/100)
Wind_Power_Output = GRAPH(TIME)
(0.00, 0.00), (1.00, 0.00), (2.00, 0.00), (3.00, 0.00), (4.00, 0.00), (5.00, 0.00), (6.00, 0.00), (7.00, 0.00), (8.00, 0.00),
(9.00, 60.0), (10.0, 80.0), (11.0, 105), (12.0, 105), (13.0, 130), (14.0, 170), (15.0, 170), (16.0, 170), (17.0, 95.0),
(18.0, 65.0), (19.0, 0.00), (20.0, 0.00), (21.0, 0.00), (22.0, 0.00), (23.0, 0.00)

Wind_Switch = 0
Wind_System_Costs = 1000.0
Wtr_Htr_Loads = Wtr_Htr_Switch*Typical_Residential_Consumption*Percent_Water_Htr/100
Wtr_Htr_Switch = 0
```

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