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Examining Direct Load Control Within Demand Response Programs

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EXAMINING DIRECT LOAD CONTROL WITHIN DEMAND RESPONSE PROGRAMS

by

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ABSTRACT

The power system is a complex entity with unique plant designs, control systems, and market strategies. For many years, engineers have developed advanced technology to keep the grid efficient and balanced. With the rise of renewable sources, some new technology and programs must be developed to keep the quality of the power system. Unlike traditional power plants, renewable energy is highly dependent on environmental factors, such as sunlight and wind, meaning the generation depends on an unpredictable source of fuel. As the grid moves to more sustainable sources, the power market faces a growing challenge of less control over the forecasted supply offered by each renewable plant. This uncertainty creates a high need to develop alternative methods to ensure the power supply always meets demand. With diminishing control over our generation, one potential solution has been to explore demand response initiatives. Demand response focuses on the engagement of consumers to reduce the electricity demand, facilitating sub-hourly efforts on the supply side. This paper will analyze the effect of demand response efforts on the participants and provide insights into potential benefits and challenges associated with implementing demand response strategies. The findings of the studies will contribute to a better understanding on the compensation structure of current Direct Load Control programs and the level of participation required for it to be effectively integrated into the power system, promoting a more reliable and sustainable future.

Keywords: power systems, demand response, direct load control.

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1. INTRODUCTION

The generation side of the energy sector operates by forecasting the necessary supply to balance with demand. By using different forecasting techniques, companies can predict a reasonable number of megawatts that each generation plant should produce to efficiently meet demand within cost minimization and other constraints. Although there are multiple algorithms to forecast schedules and generation, a problem arises when there is a sudden increase in demand for power. In this case, the generation schedule does not satisfy the demand. It is not realistic to frequently change the rate at which each generation plant is producing due to limited generator capabilities and other restrictions. For this reason, the utilities are forced to find alternatives such as buying power from the market to meet their demand.

The power market offers the flexibility to purchase and sell power in different periods, such as a day ahead or the day of (i.e., real-time) [1]. The real-time market allows utilities to adjust their generation in scenarios where demand was significantly different than forecasted, giving the opportunity for utilities to shift supply to meet consumer needs in a shorter period of time through the purchase or sale of power in the spot market.

There have been numerous studies on the improvement of the forecasting schedule algorithms when it comes to power generation [2-6]. However, it is still unrealistic to precisely predict the generation needed to meet demand at every given time, especially when accounting for sudden demand spikes. No matter how complex the algorithm is for calculating forecast demand, the value can be highly overestimated or underestimated. In the case this value is overestimated, the utility is able to sell its extra power in the spot market. This may or may not generate a profit, depending on the generation cost versus the current market price. In the case the value is underestimated, the utilities are forced to buy power to meet its demand.

Considering the volatility of the spot market, this does not always come at a fair price, but it is the price they have to pay for underestimating the demand. Having to keep the generation high enough to be prepared for the demand spikes will cost the generation companies a fortune. For these reasons, it is crucial for utilities to use the most optimal forecast schedule, which still may not give them a profit.

While the power system currently focuses on the supply side of the market, it is also important to consider the impact of consumer habits and efforts on the dispatch schedules. Consumers are solely driven by their needs and preferences, without accounting for the peak consumption times or the possible effect of their energy consumption. For example, the most common peak time for electricity consumption in a household is around 8am [7]. Unaware of the high load, a large percent of the population may wake up and lower the air conditioning temperature more than usual. This would cause an unexpected load increase on the grid, and a spike in demand, possibly leading to last-minute supply adjustments that can cost much more than it would in the day-ahead market. This behavior extends to other energy consumption devices, behaviors, and peak times. To tackle this problem, solutions have been explored such as demand side management (DSM).

1.1 Demand Side Management (DSM)

There are various articles and studies on the optimization for generation [8-13], transmission [14-17], and distribution [18-23] aspects of power. This is because the sector that studies with supply has existed for a very long time [24]. Over time, a lot of great solutions have been studied, designed, and implemented to supply power efficiently and keep the system balanced. Demand side management begun with the first energy crisis in 1973 and became well known to the public in the 1980s. This makes the demand side studies around a hundred years younger than the supply studies. For this reason, there are relatively fewer studies on the efforts that can be made from the demand side, and the impact of those programs on the power system. In a textbook, the authors state “Ultimately, there has been little research done into this theory, but it is worth bearing in mind.” [25]

While there is no solution to perfectly predict a spike in demand, there are steps that can be taken to increase the efficiency of this market. Currently, the power market runs by generating the forecasted energy required to meet with demand, without fully accounting for other efforts that can help deal with the demand spikes. One of them is the efforts that can be made from the consumer end. Demand response is when a resident voluntarily reduces energy consumption as an effort to reduce demand when it is significantly higher than forecasted [25]. It works as a way to sell the act of not using energy at times when it would benefit the grid. This is a different way to rebalance the power grid. Instead of having to purchase energy on the spot market, the utilities can reduce demand, instead of decreasing supply.

There are various methods to demand response. The two main types are price-based and incentive-based programs. The price-based programs use price signals and tariffs as incentives to participating consumers. Some examples of this are time-of-use, real-time pricing, and critical peak pricing. Time-of-use is a common program, which is an incentive for participants to use energy out of peak hours [26]. This allows the utility to have less intense demand peaks. On the other hand, incentive-based programs make direct payments to participants [27]. These types of programs can pay a fixed amount or a time-varying amount [26].

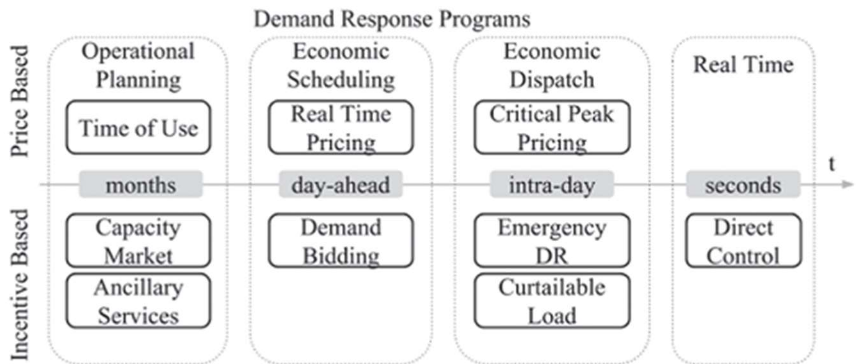

Figure 1 – Classification of Demand Response by Time [28]

The type of demand response being analyzed in this study is direct load control, which is a real time incentive-based program. Direct load control means there is direct communication between the utility and household devices [29]. Although more intense, this level of control provides the most immediate response, which classifies it as a real time response as seen on Figure 1.

Direct load control is a direct form of peak shaving. This term refers to the idea of minimizing the peak kilowatt so that it does not surpass the desired threshold. This threshold can be different depending on the time of day [30]. Through direct load control programs, the utilities have a great form of peak shaving, that can bring many advantages later discussed in this paper.

1.2 Existing Direct Load Control Programs

There are some active direct load control programs. In Florida, multiple companies such as Tampa Electric, Florida Power and Light, and Duke Energy have implemented demand response programs [31]. There are multiple types of incentive structures associated with DR, some of them are monthly bill credits, monthly bill discounts, annual incentives, one-time enrollment incentives, and no-cash incentives [32].

Tampa Electric (TECO) has a Load Management Program that offers 3.00-$3.50/kW credit per month for participating residents. This program will give TECO direct load control over chosen appliances such as air conditioning. The residents are compensated monthly even if the program is not used during that period. The application process is extensive, including an online application, a contracting process, a process of measurement and verification, and finally, the incentive payments [33]. The process can be long, but participants have the benefit of a consistent monthly payment. TECO also offers the “Time-of-Day Service”which will charge less than the flat rate when electricity is used at off-peak hours.

Florida Power and Light (FPL) has a couple of programs. Commercial Demand Reduction (CDR) will provide monthly credits to consumers that are able to shed 200 kW or more through the demand response control system. Similar to TECO, this program also compensates independently of its usage per month. There is also the On Call Savings Program,which allows FPL to cycle participants’ air conditioners during peak demand. Consumers will receive credit per appliance per month for each of the months included in the program. When activated, FPL will shut off air conditioning for 15 minutes for every 30-minute period [34].

Duke has the Backup Generator Program , in which participants allow for direct load control of their home devices and receive compensation [35]. There is a 24-hour notice before activating the event and remuneration is dependent on the generator’s capacity and event frequency. This program is more guided towards commercial properties. Duke also offers time-of-use rates, which workssimilarly to TECO’s “Time-of-Day Service” [36].

The residential program from Duke is called EnergyWise. This program offers a bill credit per month depending on the amount of usage in the household. Consumers can receive potential yearly credits of $24 for heating, $45 for cooling, $30 for pool pump, and $42 for water heater. Cooling and heating devices can be cycled for 16.5 minutes for each 30-minute period [37].

All of these programs are currently available for the public and have been used for the benefits of the participants, the utilities, and the grid. There are many ways in which this program is beneficial to all of these parties. It is important to emphasize that incentives are crucial for the feasibility of this solution, as they promote the active and voluntary participation of consumers. The more participants there are in the program, the more profound the impact on the grid is when the program is activated. Compensation is a powerful incentive for consumers to engage in the program. The first part of this thesis will feature an in-depth analysis that compares the compensation structure of current programs, providing valuable insights into the cost-effectiveness of these programs.

1.2 Benefits of Direct Load Control

In a household, air conditioning is one of the main electricity costs, as HVAC systems tend to consume very high levels of energy. The issue becomes particularly significant during periods of unexpected spikes in energy demand. This is due to the unpredictability of human behavior. During a spike in demand, residents are unaware of how costly it can be to make up for their energy consumption, especially when unplanned during forecasting. This scenario brings the need for a more proactive and cost-effective approach to manage energy consumption. Rather than investing high capital in expanding energy supply or building new power plants to meet sudden spikes in demand, it is advantageous for utility entities to propose a monetized incentive program to engage residents.

Under this framework, residents would be encouraged to participate by allowing the utility to remotely regulate their air conditioning systems for short durations, typically a few minutes. This approach leverages the thermal insulation of homes, ensuring that the indoor temperature remains within comfortable limits inside the household. This not only results in energy conservation but also a substantial relief in the demand spike. This approach facilitates a more efficient management of electricity consumption, by allowing utilities to regain control over the consumer end of the energy grid, allowing for scheduling programs to catch up. It is important to note that these programs can also apply to other appliances such as water heaters and pool pumps, but this paper will focus on air conditioning.

The use of such direct load control programs brings great advantages for utility providers. In particular, it alleviates the need to make abrupt and costly adjustments to the energy supply, especially in sub-hourly cases where energy demand fluctuations are challenging to predict. Utilities are often in a situation where their forecasted energy supply is insufficient to meet the actual demand. In such cases, utilities typically resort to purchasing additional energy from the spot market to make up for the difference, which often comes at high prices. By implementing a direct load control program, utilities gain a valuable tool to mitigate these issues. The program enables utilities to activate demand response measures, almost instantaneously reducing energy demand across the grid. As a result, utilities can be spared from buying more energy on the spot market for a high price. Instead, utilities can activate their direct load control program and almost instantly decrease their demand through a cost-effective alternative that keeps the stability of the grid.

Direct load control also has benefits for the participants. By actively engaging in this initiative, consumers stand to gain numerous advantages, ranging from financial benefits to active participation in the energy market. The shift towards greater consumer participation has been increasing since FERC 2222 opened the possibility for this solution. This order allowed for distributed energy resources (DERs) to play an active role in the wholesale electricity market. Technologies like home solar panels and electric vehicles (EVs), are given the opportunity to compete with traditional, large-scale energy generation facilities within the regional electricity market [38]. This marks a significant step away from the conventional energy structure, which has low consumer participation.

Much like home solar panels and EVs, participants of direct load control programs can also be part of the consumers who contribute to the energy market's dynamic. By actively enrolling in such programs, participants not only gain potential financial savings but also take a notable step towards renewable energy sources and sustainable energy solutions. This approach brings a broader shift toward a more balanced and environmentally conscious energy grid, where consumers, utilities, and DERs work together to address the growing demands of modern renewable energy resources.

Another benefit to the participants is that the program will decrease their electricity bills. By activating the program, utilities can strategically avoid the high energy costs, which are highest during periods of peak demand. This avoidance of costly market purchases directly contributes to a decrease in the average cost on the utility side, potentially leading to decreased future electricity rates for consumers. By participating in this program, participants play a significant role in fostering a more financially sustainable electricity market on the residential level.

Furthermore, consumers can have significant savings by having their air conditioning systems temporarily deactivated as part of the program. Air conditioning, being one of the most energy-intensive components of a typical household's electricity consumption, comes with high costs. During the program's downtime, electricity consumption for air conditioning is reduced to a minimum, resulting in savings for the participants. This reduction in energy consumption aligns with the broader goal of promoting energy efficiency and responsible consumption, contributing to more favorable financial outcomes for participants.

In addition to the potential savings and reduced energy costs, program participants receive compensation directly from their utility providers. The specific compensation amount varies depending on the incentive structure of the program, as discussed in previous sections. These compensation packages are made to ensure that participating in the program remains a financially attractive choice for consumers. Compensation of the direct load control programs is an essential part of this program.

The direct load control programs can also be highly beneficial to the grid. In transmission lines with high congestion, a decrease in load during peak times could be very beneficial. This aspect of demand response will be studied in the second study of this paper, promising further insights into the potential advantages of demand response initiatives. Utilities often must upgrade transmission lines to account for the generation being added to the grid. Various electrical studies are conducted to proactively prevent and manage congestion issues within these transmission lines. Utilities must ensure that these lines have the capacity to handle power flow even in scenarios where a nearby line may be out of service. Since there are already various steps taken to prevent this scenario, direct load control programs would not need to be activated often. However, it could still be used as a backup plan. This selective reduction in demand helps in mitigating congestion issues, thereby contributing to enhanced grid stability and reliability.

Direct load control programs also provide significant contributions to the growth of renewables. With the increase of renewables, the dispatch of conventional generation plants becomes crucial due to the limited control of the environmental resources that fuel renewable plants. Variable renewable energy (VRE) sources, such as wind and solar, inherently possess uncertainty and non-dispatchable characteristics. The consequence of this variability is that conventional power generation resources must often make abrupt and challenging adjustments to their output to compensate for fluctuations in renewable energy supply [39]. As discussed previously, it is difficult to abruptly change the dispatch of a conventional power plant due to its low flexibility. The conventional approach, which involves purchasing additional energy in the volatile spot market to mitigate these changes, can prove to be expensive. Using direct load control, utilities can use peak shaving solution instead, which can be more cost efficient and reliable.

Another issue posed by renewables is the timing. With renewables it is optimal to use energy as soon as it is generated. Energy storage technologies, while advancing, are yet to reach a level of cost-efficiency that would make larger scale more feasible [40]. As we transition toward a future with more renewable energy generation, this timing aspect becomes even more critical. In this context, direct load control programs become a valuable solution to ease the transition and prepare for the future. These programs effectively implement demand response initiatives, which not only help to peak shave the demand spikes but also facilitate the use of renewable energy. This approach to managing renewable energy helps in balancing the grid, ultimately promoting a more sustainable energy structure. The topic of renewables will be further discussed in the next section.

For the reasons discussed above, direct load control demand response programs bring benefits to utilities, participants, and the grid. For utilities, these programs significantly reduce costs during unexpected demand spikes, serving as an alternative to costly spot market purchases. For participants, it provides the opportunity to have an active role in the power market, decreased electricity bills, and direct compensation. For the grid, these programs assist in transmission line congestion issues, and facilitate the integration of renewable energy sources, helping with the grid's flexibility and sustainability.

1.3 Need for Demand Response

One of the greatest reasons why the growth in participation in demand response programs is so important is the need that renewables generate for a more reliable peak shaving program. The growth of renewable energy has created the need for numerous battery storage facilities, primarily for storing energy generated during periods of ample environmental resources availability. These storage facilities allow the accumulation of surplus energy generated during optimal conditions and its subsequent release when demand is at its highest, effectively smoothing out the peaks and valleys in energy supply. While this approach enhances grid stability and reliability, it's important to acknowledge that the establishment and maintenance of energy storage infrastructure can be quite expensive.

An emerging solution to the challenge of costly energy storage lies in the use of electric vehicles (EVs) as energy storage systems. As electric vehicles become more popular, advancements in battery technology are enabling the development of bidirectional charging features that allow EV batteries to function as versatile storage units. This innovation capitalizes on the fact that electric vehicles are typically in use by their owners for only a fraction of their operational time, typically around 4% [41]. This leaves an impressive 96% of the time when these EVs can serve as energy storage resources. This concept brings a future where parked electric vehicles provide valuable stored energy when needed most. However, it's important to note that this solution heavily relies on the broader adoption of electric vehicles within the market. The growth in renewables requires the collaborative efforts of many solutions and technologies, such as energy storage systems, demand response programs, and innovations like using EVs for energy storage. By combining them, the grid can more effectively adapt to the unique challenges that come with VREs.

An immediate solution to this challenge is direct load control. Rather than solely relying on the growth of electric vehicles or the installation of extensive battery infrastructure, we can actively promote the increased participation of consumers in direct load control programs. Through this approach, there would be an immediate peak shaving system to account for the inability to dispatch generation within renewables. The use of advanced energy management methods will be essential to maintain grid stability and reliability. It is already difficult to forecast load, even with all of the complex algorithms in place. When adding renewables to the equation, the calculation becomes incredibly more difficult. For this reason, it has been suggested that other methods of operating the power market are improved, especially demand response [42].

There have been major steps to grow renewable energy resources in the United States and Florida. In 2007, the State of Florida set executive order number 07-127. This order sets specific goals for reduction of gas emissions. It directly requested the Florida Public Service Commission to take three big actions: requiring utilities to produce at least 20% of their electricity in renewable energy, changing the statewide interconnection standard to reduce interconnection costs for renewables, and increasing net metering benefits to residential and commercial customers that contribute to renewable generation [43]. All of those steps significantly contribute to the growth of renewables and show the commitment of the government to grow in renewable energy generation. In 2008, Florida released the Energy and Climate Action Plan. This aimed to reduce emissions down to 1990 levels by 2025 and 80% below 1990 levels by 2050 [43]. This plan was a crucial step towards the growth of renewable energy. This is another example of the incentives provided by the government on the increase of renewable energy, which require demand response solutions.

Other incentives on the federal and state level that impact Florida are the Renewable Electricity Production Tax Credit (PTC), Property Tax Abatement for Renewable Energy Property, Residential Renewable Energy Tax Credit, USDA - Biorefinery, Renewable Chemical, and Biobased Product Manufacturing Assistance Program, USDA - Rural Energy for America Program (REAP) Energy Audit and Renewable Energy Development Assistance (EA/REDA) Program and the Clean Renewable Energy Bonds (CREBs) [44]. All of these programs are moving Florida towards renewable energy, and measures must be developed to handle it.

With the incentives and regulations that promote the growth of VERs, renewable plants have been rapidly rising. The more renewable resources, the more solutions should be developed and the more participation we should have in direct load control programs. While the growth of electric vehicles and utility scale batteries is crucial in the long term, demand side management offers an efficient and readily available method for peak shaving to compensate for renewable generation fluctuations. Direct load control plays a vital role in maintaining grid stability and reliability. This solution not only empowers consumers but also aligns with the needs of the grid, especially in the transition to cleaner and more sustainable energy practices.

1.4 Security Concerns

One of the issues observed with the program is security concerns. Participants have been hesitant in granting utilities access to their electricity shutdowns due to mistrust on the underlying technology. Rebuilding trust can be challenging, creating a hurdle with consumer participation. Research emphasizes the critical need to apply security measures to increase reliability and secure the privacy of participants.

A study found that participants tend to mistrust the technology required for this program, specifically the ICT infrastructure and the connected appliances [45]. The issue with trust is that once it has been lost, there is a very low chance of getting it back. Meaning it can be difficult to convince the consumer to participate in a program where they have had a bad experience or even heard of someone that had a bad experience. Other studies have pointed out that more research must be done to improve privacy and reliability of this system [46]. When implementing the necessary advance metering infrastructure (AMI) for the direct load control program, some privacy issues arise. This is specifically related to possible malicious meters that can affect the entire system. To avoid this issue, there are inspections that must be done on the metering to ensure user privacy [47]. There are also methods to increase smart mete privacy through the use of storage devices [48-49].

There have been multiple solutions to tackle this issue. One of them is the utilization of a home (local) area network (HAN), which can give reliable feedback on outages, power quality and other useful data through a smart interface along with security monitoring [49]. There are other solutions to address security concerns within demand response programs. Event-oriented dynamic security device mechanisms can provide security access service, security communication service, and security analysis service. All in effort to avoid attacks such as eavesdropping and decryption of packets within the program [50]. With the use of these proven technologies, it should become much less difficult to incentivize consumers to participate in direct load control programs.

1.5 Current Regulations and Statistics

FERC has made significant contributions to the regulations in relation to demand response programs. Order No. 719 made contributions to increase demand response participation within organized energy markets by making it be treated more fairly and similarly to other resources. In 2016, the Supreme Court upheld Order No. 745 in FERC v. Electric Power Supply Association. This Order required that each RTO and ISO pay demand response participants according to the market price for energy. One of the relevant documents required by FERC was the National Assessment & Action Plan on Demand Response through the Energy Independence and Security Act of 2007. This document was an assessment of the potential seen within demand response programs and a plan on the future of the program. Since Section 1252(e)(3) of the Energy Policy Act of 2005, FERC has been required to release an annual report on demand response resources and data on the implementation of advanced meters. The report shows the current enrollment in programs per census division, with the South Atlantic having a growth of

659,100 participants in demand response programs from 2019 to 2020. This is a 17.2% growth in one year, representing the huge impact that the demand response programs are having.

Table 3-1: Potential Peak Demand Savings (MW) from Retail Demand Response Programs by Census Division (2019 and 2020)

Census Division	Annual Potential Peak Demand Savings (MW)		Year-on-Year Change	
	2019	2020	MW	%
East North Central	5,362.8	4,909.7	-453.1	-8.4%
East South Central	4,343.1	3,797.0	-546.0	-12.6%
Middle Atlantic	1,463.6	1,504.8	41.3	2.8%
Mountain	1,968.0	2,142.9	174.9	8.9%
New England	179.3	248.5	69.3	38.6%
Pacific	1,803.2	2,346.3	543.1	30.1%
South Atlantic	8,106.8	7,197.1	-909.8	-11.2%
West North Central	5,554.1	4,689.5	-864.5	-15.6%
West South Central	2,238.7	2,634.2	395.5	17.7%
Total	**31,019.5**	**29,470.2**	**-1,549.4**	**-5.0%**

Source: 2020 Form EIA-861 Utility_Data_2020 data file, 2020 Form EIA-861 Demand_Response_2020 data file, 2019 Form EIA-861 Utility_Data_2019 data file, and 2019 Form EIA-861 Demand_Response_2019 data file.

Note: Although some utilities may operate in more than one state and Census Division, EIA data are reported by utility at the state level. Commission staff has not independently verified the accuracy of EIA data, and Commission staff is aware that there may be inconsistencies between data reported to EIA and other data sources.

Figure 2 - Potential Peak Demand Savings (MW) [51]

One of the most interesting charts on the 2022 Report on Demand Response and Advanced Metering is the potential peak demand savings from retail demand response programs. This chart shows the annual potential peak demand savings in megawatts per census division, which gives an idea of how well these programs have been performing in the United States. Within all customer classes, there are 4,909.7 MW that can be potentially saved during peak demand in the South Atlantic [51].

Residential savings account for 3,287.2 MW, which represents 66.95% of total savings in the South Atlantic. The number of participants on the program that are on the residential level is not shown, so the total number of participants in the South Atlantic will be used as an estimate. The 4,497,326 participants bring the number of megawatt savings to 0.109 kW per participant. This number is low when considering the number of megawatts that a household can save when turning off their A/C for a couple minutes. The average air conditioning system uses somewhere between 3 kW to 4 kW [52]. Using an average of 3.5 kW, we can see that the 0.109 kW per participant represents only 3.11% of the power consumption of an air conditioning system. This shows that utilities are making low use of their program and should take more advantage of it.

In a study conducted by Florida Solar Energy Center (FSEC) [53], the base case for the electricity consumption in a day is 28.8 kWh. The use of the AC will vary throughout the day, but since we don't know what time of the day a utility may shut down the AC, we will assume that the use in electricity from the AC is the same throughout the day, bringing the hourly consumption to 1.2 kWh. If a utility is shutting down a household's A/C for 15 minutes, the savings per household should be a quarter of 1.2 kWh, which is 0.3 kWh. This value will be used for calculations in the study.

Other regulations may come from other institutions such as the Public Utilities Regulatory Policies Act (PURPA), Smart Grid Interoperability Standards, ISO/RTO Market Rules, Environmental Protection Agency (EPA) Regulations, Department of Energy (DOE) Regulations, and others.

2. ANALYSIS ON CURRENT DLC PROGRAMS

The first part of this study will be analyzing current Direct Load Control (DLC) programs with a focus on the consumer end benefits. This section will provide insights into the specific financial benefits that customers can receive by participating in one of three DLC programs. Different outcomes will be analyzed depending on different levels of activation. One of the sources of data used in this study will come from transactions made in SEEM.

2.1 Related Work

There have been major studies on different techniques to optimize energy and cost efficiency in terms of household appliance control. One study developed an algorithm for a controller that optimized demand side management using current and near-future tariffs and appliance constraints. Their conclusion showed that the most important factor when it comes to consumer involvement is their convenience [54]. As algorithm optimization continues to advance, it remains clear that there must be a compelling incentive that motivates individuals to consider participation in DLC programs. This highlights the crucial importance of ensuring that consumers are fairly incentivized to participate in demand response programs.

Electricity consumption on a residential level represents a huge portion of the total consumption in the US. About one third of electricity is used by residents, which is mostly driven by air conditioners, water heaters, and space heaters. [55] This shows the potential that there is in the US when it comes to demand response programs on a residential level. One of the main causes of the delay in this process is the lack of participation in the programs.

In 2022, there was a study that analyzed the different motivations that impact the decision of consumers when deciding whether to opt into direct load control programs. This study analyzed many different consumer characteristics such as education, income level, and age group. The study identified three clusters. The first cluster is identified as a group of people that is interested in technology and home automation, with a preference on environmental concerns over financial. The second cluster showed a low interest in the technology, having its main motivator being a contact associated with the program. The third cluster was identified as neutral since there seemed to be no preference for a specific type of motivator [56]. Considering that none of the clusters showed a significant connection to the compensation aspect of the program, it suggests that there is room for improvement in this area. While the interest in technology and environmental factors emerged as the most prominent motivating factor, which surely aligns with the program's objectives, it's noteworthy that none of the clusters were primarily driven by financial motivation. This observation shows the need to explore and enhance the financial incentives associated with the program to better align them with the motivations of potential participants.

Another study was conducted on the enablers and barriers associated with consumer engagement in direct load control programs on the residential level. A survey was conducted in ten different households to understand the motivations behind participation in the direct load control program. Eighty percent of the participants said that they have joined for reasons of benefiting the society economically and environmentally, while only forty percent of the participants said they joined due to the financial payments [57]. This shows that participants have more motivation from the environmental benefits of direct load control programs than the financial benefits. Similar to the previous study, this leads to the idea that the payment structure needs to be reevaluated.

In a project run by EcoGrid, 2000 households participated in a study. During the process, consumers were asked for their motivation when deciding to participate. The three main reasons were being able to partake in something beneficial for the environment, followed by being part of something new and exciting, and third because of energy consumption. At the end of the experiment, participants were asked if they felt like the project helped them achieve their motivation goals. Participants responded that they felt like they achieved the first two goals by helping the environment and being part of the initiative. Although they did not feel as high achieved in terms of lowering their energy consumption. At the end of the project, the participants felt the positive impact of demand response programs and stated they would recommend it to other people [58]. This project highlights the potential for more activation of the program. The participants expressed a strong contribution sense towards environmental sustainability and were drawn to the innovative aspects of the program, although there was a lack of satisfaction in achieving significant reductions in energy consumption. This leads to believe that utilities are not taking advantage of the program and could take more advantage of its use. By activating the program more times, the utilities would gain more benefits through more energy savings and the participants would be more satisfied with their lowered energy consumption. This project also contributes to the potential within the financial structure, as the compensation aspect did not emerge as one of the top motivators for participants.

A survey in a Swedish town examined the interests and motivations of consumers in demand response programs. The study was split into two groups: respondents living in apartments and respondents living in detached houses. This was mainly because apartments are less likely to have the required smart metering for the program. Something to note is that the group living in houses has a significantly higher income, which may impact the results from the study. In the group of respondents that live in detached homes, 60% stated that they do have interest in improving their energy habits. In the apartment group, 41% showed a similar interest. This shows that the public mostly does have interest in partaking in the improvement of energy habits. After being presented with more information on the benefits of demand response, the numbers increased to 61% in apartments and 69% in detached houses showed interest in demand response programs. A particularly interesting question from the study was the monetary savings threshold that would incentivize them to join the program. Remarkably, 24% of participants claimed they would participate in the program for no more than 250SEK per month, which is equivalent to USD $22.91 per month [59]. This value is relatively high compared to the existing DLC programs. This shows that participants are expected to be paid much more to participate. The survey concluded both financial and environmental motivators are important drivers.

The participation in direct load control programs has been lower than expected, and various studies have explored the motivations and drawbacks within DLC. One of the barriers that has stopped customers from joining the programs is sense of losing control [60]. Since utilities assume control over certain household appliances, consumers have a feeling of reduced autonomy over when and how they can use these devices, especially with how unpredictable the activation of DLC can be. The paper mentions that this can be related to the American value of the freedom in making decisions.

There are many types of demand response programs when it comes to air conditioning. One of them is where the utility has full control of the A/C power and has the ability to shut it down when necessary. Another type is with the use of a smart thermostat, allowing the utility to make adjustments that do not involve complete shutdown but rather alterations to the appliance's settings based on the utility's requirements, overriding the participants' original preferences. While there is undoubtedly a financial incentive to participate in these programs, this study dives into the additional motivations and factors that influence consumer decisions to participate in DLC programs.

Utilities have provided different levels of control to the participants in DLC programs. For instance, certain programs allow consumers to choose their level of interruption time, with higher levels of power interruptions corresponding to increased compensation. In contrast, other programs allow participants to opt out of the program when it's activated. While a few utilities issue warnings prior to A/C shutdown, this advanced notice may not afford consumers sufficient time to make decisions, given that the program is designed to respond to unexpected demand spikes. Out of the 80 programs included in the study, only two claimed that the consumers had the right to override the activation of the program. Most often, the consumer has no choice to override the activation and the only option is to leave the program. It is important to note that this study was not conducted in Florida, and participants were required to have a non-flat rate on their utility bill to participate.

Participants of the study were given an option between two programs. Program A was for a program that would completely shut down the A/C when activated and Program B would simply adjust the thermostat temperature. If the participant answered “Maybe” or “No” to either of the programs, there was a follow up question was whether they would like to receive a $30 reward per summer or the ability to override the program when activated. For program A, 52.7% of participants said yes. Eleven percent of the participants were considered “control-motivated converters”, which is larger than the five percent that was considered “money-motivated converters”. For program B, 48.65% of participants said yes. Nine percent of the participants considered “control-motivated converters”, which is larger than the six percent that was considered “money-motivated converters”.

The results of the study clearly indicate a strong interest among consumers in having more control choices over incentive payments within direct load control (DLC) programs. However, there is a potential drawback associated with this desire for control, as consumers may be inclined to override program activations, especially when they coincide with peak usage hours when air conditioning or other appliances are in high demand. Granting consumers the option to override program activations can introduce unpredictability and make it challenging for utilities to accurately estimate the amount of power they can curtail, as consumers could simply turn off the program once it's activated.

It's essential to recognize that the incentives offered to consumers play a significant role in their decision-making process. The paper mentioned a study that stated residents did not frequently use the override feature, it is mostly to seek reassurance. DLC programs are typically activated during times of high demand when utilities genuinely require the reduction in consumption, making it difficult to balance consumer preferences for control and the program's effectiveness in managing peak load and grid stability. Finding innovative ways to provide consumers with more control while maintaining program reliability is a complex challenge that utilities must address to encourage broader participation in demand response initiatives.

It is interesting that the study used a very high reward value compared to the credits offered by current DLC programs. The ones mentioned on previous section are often offer less than ten dollars per month. In the survey, about half of the participants stated that they were willing to join the program before receiving the follow-up question regarding the incentive and the control option. This suggests that many individuals are inclined to participate for reasons beyond financial or control considerations. Possible explanations for this early willingness be due to participants that pay a non-flat rate, so they could be motivated by the benefit of avoiding higher rate charges. This scenario might be more common in regions outside of Florida, since flat rates are common in that state. It's also possible that some participants opted to join the program before receiving the question about the incentives and control options simply because they were not initially provided with this information. The study did not evaluate the reasons why participants said “Yes” to participating in the programs.

Other research papers have published new incentive designs for direct load control [61]. In this paper, a method referred to as Direct Load Scheduling (DLS) is analyzed. Unlike traditional direct load control programs that grant utilities complete control over participants' appliances, the DLS program offers a different approach. Rather than selling the right to fully control the appliances, DLS aims to purchase more flexibility from participants. The operation and incentives of this DLS program are done in real time, and the customers are able to customize their options by actively choosing which actions to take within the program. Based on limits set by the participants, the utility will have permission to schedule their high energy consuming tasks so that it better aligns with the grid’s schedule.

One of the drawbacks of this program is that it requires the participant to be very active, and some may not be willing to dedicate that much time and make every decision. However, this addresses the previously discussed issue of lack of control. Since consumers are not allowed to decide whether they will allow the utility to make changes to their schedule, participants may regain the sense of control to their appliances while still contributing to demand response.

It’s crucial to acknowledge that this program may not offer the same level of benefits to utilities compared to traditional direct load control programs. By allowing participants to choose their level of participation, the utility may face challenges in accurately calculating the energy savings achieved when activating the program. Despite this, the DLS program represents an innovative approach that places greater emphasis on consumer autonomy and flexibility, aligning more closely with their preferences while still contributing to demand response efforts.

Another paper goes over an algorithm that optimized the cost reduction within DLC. In this study, the authors introduced an algorithm that leverages Integer Genetic Algorithm and explored three different strategies: 1) consumer control demand-side management (DSM), 2) utility control DSM, and 3) utility and consumer control DSM. In each of these strategies, data was collected on the target, actual, and optimized loads in each residential and industrial scenarios. The results show that the third strategy was the best option. It reduced the peak demand by 14% and reduced costs by 3.1% in the residential area [62]. What's particularly interesting is the substantial reduction in energy consumption compared to the cost savings. These numbers serve as benchmarks and a basis for understanding the potential improvement that can be made from DLC programs on both peak reduction and cost reduction.

TABLE I I I
PERCENTAGE PEAK DEMAND REDUCTIONS

strategy number	K_1	K_2	Peak reduction in industrial area	Peak reduction in residential area
1	1	0	%9	%5.9
2	0	1	%5.7	%4
3	0.5	0.5	%5.1	%14

TABLE I V
PERCENTAGE COST SAVING

strategy number	UTILITY COST SAVING	Industrial Cost saving	Residential Cost saving
1	%0.2	%2.5	%4
2	%4.5	%0.1	%0
3	%2.5	%2	%3.1

Figure 3 - Results from [62]

One thing to note on the two previous papers is that they form an algorithm that optimizes cost and effectiveness of the direct load control program but fail to address a concrete monetary value on how much the participants can save. There are multiple papers with strategies such as dynamic programming and integer linear programming that focus on optimizing the algorithms. However, what these studies often overlook is the real impact these optimized algorithms have on program participants. No matter how efficient the program's technical aspects are, the fundamental success of any DLC program is the participation of consumers.

2.2 SEEM

SEEM is the Southeast Energy Exchange Market, a new solution to reshape the bilateral trading market. It facilitates sub-hourly trades where participants can buy and sell power in very close proximity to the time of energy consumption. This platform unleashes a new era of flexibility in the electricity market through the use of unreserved transmission. SEEM focuses on sub-hourly trades, which sets itself apart from the conventional model. This allows entities to respond much more efficiently to fluctuations in energy supply and demand. SEEM has seen rapid growth since its start in November 2022. Since then, it has nearly 23 entities with substantial capacity over 180,000 MWs during the summer and 200,000 MW during the winter. Some of the participants include large utilities such as Dominion Energy, Duke Energy, JEA, PowerSouth, Seminole Electric Corporation, Southern Company, Tampa Electric Company, TVA, and many others [63].

SEEM’s ability to adapt to the rapid changes in the energy landscape positions it as a crucial player in the transition to a more sustainable and efficient power system. The reason SEEM will be used for this study is because both SEEM, and direct load control programs operate sub-hourly. This means that just like SEEM, consumers participating in direct load control programs should have a fair price. Another reason why SEEM data will be used for this study is because the website has public data that is very useful for analyzing fluctuations in price.

2.3 Compensation Analysis

This study will analyze existing DLC programs in the state of Florida at different levels of activation time. There will be a focus on the air conditioning control to ensure consistency in the examination. The primary objective of this study is to assess the cost-effectiveness of various DLC programs, each operating at different levels of activation time. This study will investigate the cost of three direct response programs and make a comparison with the corresponding cost of buying energy from the spot market. The proposed research will analyze existing demand response programs using real data from the SEEM market. To enhance the effectiveness of these programs, the study will not only evaluate existing demand response schemes but also propose potential modifications aimed at optimizing the incentive structure.

A couple values used for this study will come from the SEEM public data [63]. The two months that will be analyzed are July 2023 for the summer and January 2023 for winter. A Python script was written to gather all of the hourly data into one database. As SEEM provides its data in individual CSV files for each date, the script systematically read and processed the files for all the dates within the months under examination, creating a single comprehensive database for the analysis.

Using the Power BI, a dashboard was created to analyze the data from both months. Considering that there are some of the hours where no trades were made, some of the data points had the price per megawatt hour as zero. To ensure the accuracy and reliability of the analysis, such cases have been excluded from the dashboard and study. The dashboard displays a graph of the price in $/MWh for each month. Other helpful data is calculated such as the median, average, variance, and standard deviation of the price per month. The median and averages are good values to use for an estimate of what the price per megawatt hour at the time of a demand spike when a utility needs to buy power in the sub hourly market. The variance and standard deviation are both calculated so that we can observe how much variation there is in this market. Since SEEM is a new platform, the participants and trades are still settling in. For this reason, we can observe large variance and standard deviation values. Another reason this happens is because the market for the sub-hourly energy is not as consistent as other markets. The utilities are advised by SEEM to not replace the use of the bilateral market with this platform. SEEM was built to assist in the energy trade in cases where it can be more applicable than the bilateral market. Another set of data displayed on the dashboard is the top and bottom five prices for that month. It is important to note that the prices can have a high variance during peak and non-peak hours as well as different times of the year.

In the month of January 2023, the average price per megawatt hour was $33.47/MWh or $0.03347/kWh. This value will be used to represent what a utility would need to pay in case there is a spike in demand and choose to buy the energy instead of activating a demand response program. In the month of January there was a high standard deviation of 6.58 and a high variance of 43.27. The lowest transaction price was at $15.07/MWh and the highest was at $66.96/MWh.

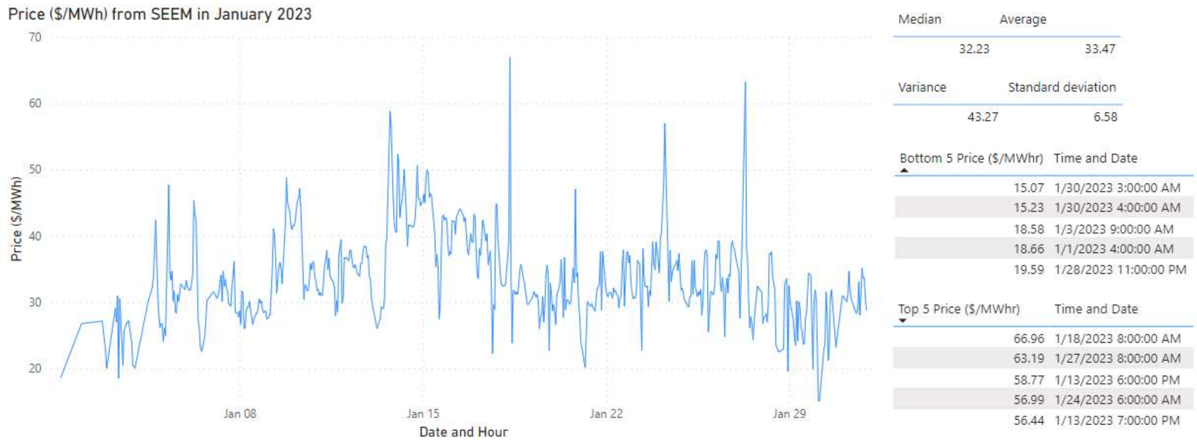

Figure 4 - SEEM Data from January 2023

In the month of July 2023, the average price per megawatt hour was \$29.06/MWh or \$0.02906/kWh. This value will represent the price for each megawatt hour in the summer months, and the value from January 2023 will be used for the winter months. There were high variance and standard deviation values of 54.96 and 7.41, respectively. To simplify this study, the annual average for the cost of a megawatt hour in the SEEM market will be calculated with the assumption that a year has six summer months and six winter months. The average of the January and July averages bring the average annual price per megawatt hour to \$31.27, or \$0.03127 per kilowatt hour.

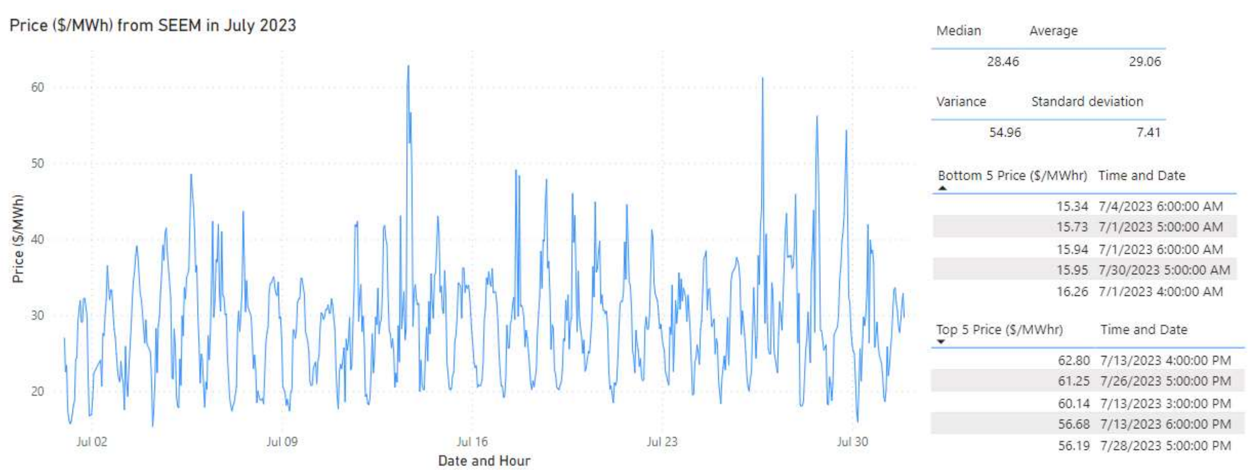

Figure 5 – SEEM Data from July 2023

TECO

Tampa Electric (TECO) has a Load Management Program that offers \$3.00-\$3.50/kW credit per month for participating residents. The two compensation values depend on the option of the program that the participant chooses: Cyclic or Continuous. The Cyclic will credit \$3 per kilowatt from April to October. The Continuous will credit \$3.50 per kilowatt all year [64]. Besides the credit given by the program, the participants could also save money on their electricity bill since they would consume less energy than they would if not enrolled in the program. The TECO electricity rates in Florida are about 13.934 cents per kilowatt-hour [65].

No information on the interrupting schedule was found, and for this reason we will assume different levels of activation based on the schedule from FPL's Call Savings Program, which is a maximum of 3-hour interruption time per day. There are three cases that will be taken into account, those will be the activation for the 3-hour total interruption time once a month, twice a month, and every week.

The table presents potential cost savings for program participants when DLC is activated for a total of three hours or less every week. In this scenario, the estimated annual savings on the electricity bill for a participant would be under \$15. This figure might not initially seem enticing to consumers, especially when compared to the compensation prices from the studies outlined in the related work section. Although it's important to recognize that this represents just one part of the overall compensation value.

It's important to acknowledge that the frequency of activation in this study is notably high, especially when considering that unpredictable demand spikes occur less frequently. However, as we progress into the future and VERs become more predominant, utilities may reevaluate and consider a more frequent activation schedule. It's worth noting that the program's rules do not prohibit such an approach, and the flexibility to adapt to changing energy generation remains a critical aspect of DLC programs.

Table 1 – Load Management Program Savings

Electricity Rate per kWh	Interrupting Time in Hours	Times per Week	Months Active	Average Hourly Consumption in kWh	Total Hours	Saved Yearly kWh Consumption	Yearly Savings
0.13934	3	0.25	7	1.2	21	25.2	3.51
0.13934	3	0.5	7	1.2	42	50.4	7.02
0.13934	3	1	7	1.2	84	100.8	14.05

Something that should be considered when analyzing the cost per kilowatt at peak demand hours is the demand charge. The demand charge is calculated based on the maximum demand that the customer was using during a specific period of time when the demand was at peak. This charge helps account for the fact that energy is much more costly at times when there is a spike in demand. Demand charges started with commercial and industrial level buildings but is quickly growing into the residential level with the growth in smart metering [66]. The rate TECO uses for the demand peak will be used to represent a fair value that could be paid the consumer, since both represent the price of energy being consumed during peak demand times where the system may be overloaded or during a spike in demand.

TECO's demand charge rate is $10.92/kW [67], which is over three times larger than the current rate that is being used for TECO's demand response program. Assuming the A/c systems typically uses 3,000 to 4,000 W [52], 3.5 kW will be used as an average for this study. On the

Cyclic and Continuous programs, a participant could expect to gain $10.50 and $12.20 per month respectively. However, if the rate was the same as the demand charge rate, using the same program activation assumptions from above, the participants could gain $38.22 per month. This value would be much more attractive to consumers and likely increase participation in the program.

Table 2 – Load Management Program Yearly Credit

Credit per kW	Months Active	kW in Typical A/C	Montly Credit	Yearly Credit
3	7	3.5	10.5	73.5
3.5	12	3.5	12.25	147
10.92	12	3.5	38.22	458.64

Overall, the TECO Load Management Program compensation seems to not align with their demand charge. More studies should be done on the price difference between the DLC program compensation and the demand charge rates. Given that both DLC and demand charges account for the cost of energy consumption under comparable scenarios, a closer alignment between these two pricing structures is expected. Further studies in this domain could offer valuable insights into achieving a better relationship between compensation and demand charge rates within the energy market.

FPL

Another one of the programs to be analyzed is the Florida Power and Light (FPL) On Call Savings Program, which allows FPL to cycle participants' air conditioners during peak demand. FPL claims that the involvement in this program could translate to annual savings of over $90 for participants. An interesting feature of this program is that participants receive bill credits even when the program is not activated by FPL. More detail on the credits that can be received monthly and the months where that credit applies can be found on the terms and conditions of the program [34]. It is important to note that most of the credits are not applied year-round. To become an eligible participant in this program, certain appliances are required to be enrolled. These include the central electric air conditioner and, if applicable, the central electric heater. During the months when the monthly credit is in effect, both the air conditioner and heater may be temporarily deactivated for a maximum duration of three hours each day. As per the table below, participants can anticipate a monthly bill credit of $6.00 for their Central Electric Air Conditioner over the span of seven months. Therefore, the total annual credit for a participant in this program amounts to $42.

Appliance	Applicability	Monthly Bill Credit
Central Electric Air Conditioner	April – October	$6.00
Central Electric Heater	November – March	$2.75
Conventional Electric Water Heater	Year-Round	$1.50
Swimming Pool Pump	Year-Round	$1.50
Prior Participants Only (Cycle Option) - Central Electric Air Conditioner	April – October	$3.00
Prior Participants Only (Cycle Option) - Central Electric Heater	November – March	$2.00

Figure 6- FPL Program Details [34]

Note that there is a different credit for the prior participants. The credit is lower because their interruption schedule is different. The A/C and heater can only be shut down for 15 minutes for every 30-minute period, with the same accumulative interruption period as new participants. It's important to acknowledge that the shutdown duration and interruption limit for the air conditioner can potentially be extended if there is a need for greater demand reduction.

The average consumption of A/C in a home in Florida will be used to evaluate the pricing per megawatt hour using the FPL On Call Savings Program. In a study conducted by Florida

Solar Energy Center (FSEC) [53], the base case for the electricity consumption in a day is 28.8 kWh. The use of the AC will vary throughout the day, but since the time of the day FPL may shut down the AC is unknown, it is assumed that the use in electricity from the AC is the same throughout the day, bringing the hourly consumption to 1.2 kWh.

The estimated rate of electricity from FPL is 13.995 cents per kilowatt hour [68], and the participants can save on their electricity bill by not consuming energy during that time when their air conditioning system is shut down. Assuming the program is activated every other week, accumulating a total interruption time of three hours over the span of seven months, participants could benefit from the credit approximately 28 times. This equates to a significant energy savings of 50.4 kWh, translating into around $7.05 in electricity cost savings during the seven-month period. It is important to note that this estimation may vary, contingent upon the frequency of A/C shutdowns initiated by FPL. Either way, it serves as a reasonable approximation of potential energy savings. In addition to these electricity bill savings, participants receive credits from FPL, which were previously calculated.

This calculation shows that most of the program benefits stem from the credits being given by FPL compared to the electricity savings. Using this value to estimate the price that FPL is paying for each kWh results in $0.415/kWh. This rate significantly exceeds the cost of purchasing energy from the SEEM, which stands at approximately $0.03127/kWh. This comparison highlights the fact that FPL is willing to pay a premium, at over ten times the market price, to encourage consumers to reduce their energy consumption. It underscores the immense value that utilities place on this flexibility, to the extent that they are willing to invest tenfold in ensuring participants' involvement in the program. This large difference between the price FPL pays and the SEEM rate shows the importance of demand response initiatives in promoting more efficient energy consumption practices.

Given that FPL is paying participants a flat rate, it is possible to calculate how many interruptions would need to be made so that they would get their money's worth. Meaning that they would activate the program enough times that the high number of megawatt hours saved through the program lowers the cost be the as low as the SEEM price. Below is a calculation table used to calculate the value FPL is paying per megawatt hour for different assumptions for the number of activations per week.

Table 3 – On Call Program Analysis

Electricity Rate per kWh	Interrupting Time in Hours	Times per Week	Months Active	Average Hourly Consumption in kWh	Total Hours	Saved Yearly kWh Consumption	Yearly Savings	Value Being Paid by kWh
0.13995	3	0.25	7	1.2	21	25.2	3.53	1.66667
0.13995	3	0.5	7	1.2	42	50.4	7.05	0.83333
0.13995	3	1	7	1.2	84	100.8	14.11	0.41667
0.13995	3	2	7	1.2	168	201.6	28.21	0.20833
0.13995	3	7	7	1.2	588	705.6	98.75	0.05952
0.13995	**5.71**	7	7	1.2	1119.16	1342.992	187.95	0.03127
							SEEM:	0.03127

This table clearly demonstrates that even if FPL were to activate their demand response program every single day for the maximum duration of three hours, they would still be paying approximately $0.05952 per kWh. This rate remains higher than the pricing offered by SEEM. To match the SEEM pricing, FPL would need to extend their maximum shutdown time to approximately 5.71 hours per day. It is important to note that if the air conditioning of a household was shut down for that large of a number, the temperature would potentially deviate enough from the settings that it would cause discomfort for the participants. FPL's DLC program appears to be providing participants with highly favorable compensation. Given this, it is strongly recommended that customers are better informed about the substantial payments they are receiving through their participation in the program. This transparency would not only benefit the consumers but also underscore the attractiveness of the program, potentially encouraging more participants.

Duke

Duke has the EnergyWise program, which has a very similar system of bill credit to the FPL program. Some of the monthly and yearly credit potentials are on the table below. The credits are given in "potential" since they depend on the consumer's kilowatt usage. If the consumer utilizes over 600 kWh in a cycle period, the credit rates will change accordingly [37]. For the simplification of this study, potential savings will be assumed to be the monthly credit received by the participant. It's worth noting that in reality, these savings could vary, potentially being higher or lower depending on various factors and individual usage patterns.

Year-round Program		
Options	Monthly savings potential*	Annual savings potential*
Heating	$8	$24
Cooling	$5	$45
Pool pump**	$2.50	$30
Water heater**	$3.50	$42
TOTAL ANNUAL SAVINGS OPPORTUNITY		$141

*Credits prorated according to use over 600 kilowatt-hours (kWh) per month. Monthly credit may vary based on equipment compatibility and number of appliances enrolled.
** Optional for year-round participants.

Figure 7 - Duke Program Details [37]

The Duke EnergyWise program has different package plans for different states. In North Carolina, for example, the same EnergyWise program is applied through thermostat adjustment instead of a full shutdown. Qualified participants receive a $75 bill credit for the first year they enroll their thermostat in. For each additional year, the credit increases by $25 [69]. Duke states that the devices can also be shut down during system emergencies, but these are a rare occurrence. Due to the focus of this study being on complete shutdowns, this program will not be further analyzed. However, it is interesting to compare the difference in bill credits. When signing up for a program that completely shuts down the air conditioning system, the potential credit is about $69 per year, as calculated in the table below. But when signing up for the thermostat adjustments, participants receive a guaranteed $75 credit per year, and a guaranteed increase that adds a third of the initial credit. Participants do not have the option to choose between the two programs, since the thermostat adjustment program is not offered in Florida. However, it is interesting to compare and note that the thermostat adjustment option pays more than the full shutdown option.

Table 4 – EnergyWise Yearly Credit

Monthly Bill Credit	Months Active	Cumulative Credit
8	3	24
5	9	45
	Total Yearly Credit	69

The chart from Duke divides air conditioning devices into heating and cooling. Heating from December to February and cooling from March to November. Both are cycled for up to 16.5 minutes for each 30-minute period. This structure is also very similar to the FPL program evaluated above. For the Duke calculation, we will evaluate the 16-minute periods at 3, 5, 10, 20 and 100 times per week on the table below. Note that if Duke activated their program 100 times per week, it still does not exceed the total amount of times that Duke can activate for. Since it can be activated for 16 minutes out of each 30-minute interval, the program can be activated up to 48 times per day and 338 times per week. Similar to FPL, Duke also appears to be compensating consumers at a reasonable rate for their demand flexibility. If Duke were to match the pricing it would pay at the SEEM market, it would necessitate the activation of the program approximately 140 times per week.

The average price for Duke's electricity rates will be used to calculate the savings in the electricity bill of participants. As of June 2023, Duke has an average of 16.84 cents per kilowatt hour for a residential property in Florida. Based on the 16.5-minute interruption period, which is 27.5% of an hour, the estimated savings based on different levels of activation of the program are calculated below. The total savings becomes very high once the program is activated enough times to give Duke a fair demand savings, raising cost savings to $372.11 per year.

Table 5 – EnergyWise Program Analysis

Electricity Rate per kWh	Interrupting Time in Hours	Times per Week	Months Active	Average Hourly Consumption in kWh	Total Hours	Saved Yearly kWh Consumption	Yearly Savings	Value Being Paid by kWh
0.1684	0.275	3	12	1.2	39.6	47.52	8.00	1.4520
0.1684	0.275	5	12	1.2	66	79.2	13.34	0.8712
0.1684	0.275	10	12	1.2	132	158.4	26.67	0.4356
0.1684	0.275	20	12	1.2	264	316.8	53.35	0.2178
0.1684	0.275	100	12	1.2	1320	1584	266.75	0.0436
0.1684	0.275	139.5	12	1.2	1841.4	2209.68	372.11	0.0312
							SEEM:	0.03127

While Duke technically has the authority to implement a large interruption time, it becomes impractical in terms of maintaining air conditioning comfort, similar to the conclusions drawn from the FPL program. A high number of shutdowns can lead to temperature fluctuations within the house, potentially reaching uncomfortable levels as insulation systems fail to maintain the desired temperature. This discomfort could result in participants opting to leave the program voluntarily. For these reasons, Duke is unlikely to engage in a high number of program activations for extended durations.

It's also important to recognize that the DLC programs are primarily designed for addressing emergency situations that do not happen frequently. Therefore, their intended purpose is not to regularly implement extensive A/C shutdowns but to provide a mechanism for peak demand during unusual circumstances. Another interesting factor is that even when using the highest price at SEEM for each of the January and July data, the utilities still seem to be more than fairly compensating their participants when comparing the value to the bilateral market.

2.4 Considerations

There are multiple factors that may have impacted the results of this study. One of the causes for the results for both FPL and Duke may be the use of wholesale market prices to examine the value of energy consumption at peak time. It is worth considering that during times of peak demand, electricity becomes significantly more valuable than the wholesale market price would suggest. This is especially evident when factoring in the demand charge, as previously discussed in the previous section. That charge shows that the price of electricity at its peak is so much higher that the utility must add an extra charge to make up for that use. Therefore, the wholesale market price alone may not fully capture the true value of energy consumption during peak hours. This highlights the importance of exploring additional cost components, such as demand charges, to gain a more accurate understanding of the economics in peak energy consumption. This may also affect the savings that were estimated in this study. The savings of participants are expected to be much higher considering that this study used an average, and not a value that represents the higher cost of electricity during peak times when DLC would be activated.

Another critical factor to consider are peaker power plant units. These power plants are designed specifically to meet demand at the times when energy consumption is at its highest. The unique characteristic of peaker power plants is that they have substantial startup costs, which can be quite expensive. Since the peaker power plants are used for short periods of time, the startup cost can significantly inflate the cost of the energy they generate. It is important to note that this is precisely the type of energy used during demand response program activations. Therefore, a more equitable and realistic comparison would involve considering the pricing of peaker power plants as opposed to the wholesale market price alone. This approach would provide a more accurate assessment of the value of energy consumption during peak times and better reflect the economic of demand response programs. Some of the peaker power plants units in Florida are mentioned in the paper by Physicians, Scientists, and Engineers for Healthy Energy (PSE) [70]. The Indian River peaker plant, for example, only produces during peak hours. According to the paper, it runs only about 4.9 hours every time it starts and has a capacity factor of about 0.7 percent. The Marathon Generating Peaker Plant is capable of generating 11MW. Considering that each participant contributes with about 3.5 kW of air conditioning [52], a total of 38,500 participants could avoid the cost of adding a similar peaker plant. This is a relatively low number of participants considering the total of 4,497,326 participants in the South Atlantic, according to the 2022 Report on Demand Response and Advanced Metering [51].

Another one of the factors impacting this study is the possibility that the bilateral market prices may not reach such high levels because utilities are already utilizing these demand response programs. This would prevent the occurrence of extremely high market prices that would technically offset the value utilities are paying to participants in DLC programs. In other words, by reducing energy demand during peak periods, utilities can p avoid the price spikes that would otherwise be observed in the bilateral market and impact the results of this study. As a result of effective demand response measures, the exceptionally high prices that could have been seen in the bilateral market are avoided. For this reason, the bilateral market prices may not accurately justify the compensation that utilities are providing to participants.

Another reason why bilateral market prices may not spike during these demand hours is because programs such as demand charges are being used, which are not voluntary. Demand response programs require participants to voluntarily enroll. This variation in approach can lead to different economic outcomes and further complicates the interpretation of the value and costs associated with peak energy consumption and management. Since demand charge is not voluntary, the utilities make up for the expensive cost of generation through increasing the electricity bill rate instead of using DLC programs.

The best use of the DLC programs will come when it is the only viable option. This can happen in two ways: an emergency, or when looking into a future with renewables. In emergency situations, when the gap between electricity demand and supply spikes to critical levels, activating the demand response program becomes the only practical option to maintain the grid's stability and meet the demand. In the future, as the energy industry transitions towards a future dominated by renewable energy sources, demand response programs may become the sole viable option to manage energy consumption effectively. In such a scenario, dispatchable power generation will be limited, and demand response programs can play a pivotal role in balancing the grid and ensuring a reliable energy supply. By recognizing these scenarios, we can better appreciate the significance of DLC programs.

One great example of an emergency where direct load control could have been used is the Texas Crisis in 2021. This year, over 4.5 million households and more than 10 million people were left with no electricity in Texas for many days. Due to the cold, failures in the technical equipment caused outages that shut down 30 GW in generation. Fuel shortages and frozen equipment caused gas power plants to be shut down. Low wind and ice formation on turbines caused wind farms to go offline. The gap between generation and demand was so large that the Electric Reliability Council of Teas (ERCOT) had no option but to order a blackout, leaving many consumers with no power. The cost of power was so high that they had to place a cap at $9000 per megawatt hour [71].

Using this price as a reference for what a consumer could be paying in case of emergency, the study leads to very different results. The study will be recalculated to account for the use of a DLC program at times of emergencies. Considering the extremely high prices that come with emergency cases, utilities could have great benefits from activating demand response. In the case of the Texas Crisis in 2021, the price of $9000/MWh will be used as the spot market price to make the calculations.

The table below shows the calculated value that represents the credit that a participant would be earning in the Duke DLC program would receive in that scenario. Even if the program is activated or only once a week, the participants could be making more than they would be through a lot of the current programs.

Table 6 – DLC During Texas Energy Crisis in 2021

Interrupting Time in Hours	Times per Week	Months Active	Average Hourly Consumption in kWh	Total Hours	Saved Yearly kWh Consumption	Yearly Credit	Monthly Credit	Value Being Paid by kWh
0.275	1	12	1.2	13.2	15.84	142.56	11.88	9.00
0.275	3	12	1.2	39.6	47.52	427.68	35.64	9.00
0.275	5	12	1.2	66	79.2	712.80	59.4	9.00
0.275	10	12	1.2	132	158.4	1425.60	118.8	9.00
0.275	20	12	1.2	264	316.8	2851.20	237.6	9.00
0.275	100	12	1.2	1320	1584	14256.00	1188	9.00

Since the utilities still need to make a profit, a 30% profit was given to the utility by decreasing the compensation value of a kilowatt to $6.30 instead of $9. Even at this rate, it's evident that the program credits offered are significantly higher compared to those of previous programs. While this scenario may not be a frequent occurrence, it undeniably highlights the immense potential and efficacy of DLC programs.

Table 7 - DLC During Texas Energy Crisis in 2021 with 30% Profit

Interrupting Time in Hours	Times per Week	Months Active	Average Hourly Consumption in kWh	Total Hours	Saved Yearly kWh Consumption	Yearly Credit	Monthly Credit	Value Being Paid by kWh
0.275	1	12	1.2	13.2	15.84	99.79	8.316	6.30
0.275	3	12	1.2	39.6	47.52	299.38	24.948	6.30
0.275	5	12	1.2	66	79.2	498.96	41.58	6.30
0.275	10	12	1.2	132	158.4	997.92	83.16	6.30
0.275	20	12	1.2	264	316.8	1995.84	166.32	6.30
0.275	100	12	1.2	1320	1584	9979.20	831.6	6.30

Before reaching the point where ERCOT had no choice but to shut down consumers' power, the program activation could have acted as a valuable mitigating factor. Especially considering that the energy was not even available for purchase in the bilateral market, since so many generators were not in use. Currently, most utilities have the option to buy energy from the spot market because it is widely available. And that is because nonrenewable energy is dispatchable, meaning if more energy is needed, all they need to do is burn more fuel to generate more energy. However, as renewable energy generation becomes more predominant, the risk of situations where energy isn't readily available in the market becomes increasingly likely.

Another example of a not so extreme case was the winter storm in December of 2022. The low temperatures caused a large cut in energy generation in the South of the United States, causing a major decrease in energy supply. According to Reuters, more than 1.5 million homes and businesses lost power in the Eastern half of the United States and Texas [72]. Due to the huge decrease in power supply, there was a major spike in energy prices. This can be seen in both the bilateral market in Texas and the SEEM public data. According to Reuters, the power in the Texas power market spiked to $3,700 per megawatt hour. The table below calculates the proportional participant compensation using this value as the fair compensation for the consumer at this case and the same but accounting for a 30% profit. Columns for the results at 30% profit are marked (P).

Table 8 - DLC During 2022 Winter Storm

Interrupting Time in Hours	Times per Week	Months Active	Average Hourly Consumption in kWh	Total Hours	Saved Yearly kWh Consumption	Yearly Credit	Monthly Credit	Value Being Paid by kWh	Yearly Credit (P)	Monthly Credit (P)	Value Being Paid by kWh (P)
0.275	1	12	1.2	13.2	15.84	58.61	4.884	3.70	41.03	3.4188	2.59
0.275	3	12	1.2	39.6	47.52	175.82	14.652	3.70	123.08	10.2564	2.59
0.275	5	12	1.2	66	79.2	293.04	24.42	3.70	205.13	17.094	2.59
0.275	10	12	1.2	132	158.4	586.08	48.84	3.70	410.26	34.188	2.59
0.275	20	12	1.2	264	316.8	1172.16	97.68	3.70	820.51	68.376	2.59
0.275	100	12	1.2	1320	1584	5860.80	488.4	3.70	4102.56	341.88	2.59

This table shows the credit given to the customer per the evaluation used in the December 2022 winter storm would be much more reasonable relative to what utilities are paying customers now. For example, if a utility activated the program twice per week for 16.5 minutes and paid the value of $3,700/MWh, the consumer would be receiving $14.65 in credits per month. This value is much higher than the compensation currently being paid. Including the 30% profit for the utility, the customer would still be receiving $10.26 per month, which is higher than the current DLC programs. This shows that the price utilities are paying is in fact fair, and not high, as was suggested in previous studies.

In the SEEM data, there are a couple factors that were affected by this storm. For example, in December, during the storm days, there were near zero offers in the market. In fact, on December 28th there are two hours in the market that are not reported in the public data. The cause of this was not found, but it could be due to a system shutdown. From December 23d to 27th, there were huge spikes in the pricing. On December 23rd, the price spiked to $304.35/MWh.

Table 9 - DLC During 2022 Winter Storm Using SEEM Data

Interrupting Time in Hours	Times per Week	Months Active	Average Hourly Consumption in kWh	Total Hours	Saved Yearly kWh Consumption	Yearly Credit	Monthly Credit	Value Being Paid by kWh	Yearly Credit (P)	Monthly Credit (P)	Value Being Paid by kWh (P)
0.275	1	12	1.2	13.2	15.84	4.82	0.401742	0.30435	3.38	0.281404	0.2132
0.275	3	12	1.2	39.6	47.52	14.47	1.206018	0.30455	10.13	0.844213	0.2132
0.275	5	12	1.2	66	79.2	24.12	2.01003	0.30455	16.88	1.407021	0.2132
0.275	10	12	1.2	132	158.4	48.24	4.02006	0.30455	33.77	2.814042	0.2132
0.275	20	12	1.2	264	316.8	96.48	8.04012	0.30455	67.54	5.628084	0.2132
0.275	100	12	1.2	1320	1584	482.41	40.2006	0.30455	337.69	28.14042	0.2132

These results show that with the evaluation at this this price, the utilities would need to activate the program over 20 times a week for the customers to be compensated similarly to what they currently are. This is still a lot of activation time for the utilities, meaning that even at $304.35/MWh, the utilities will likely not be making a profit.

In this study, the peak price has been applied to the entire month. This is to account for the fact that one day when we have renewables that are not dispatchable, these effects will last for much longer. But to represent these impacts at the current levels we can use the average of the month of December, which was $54.89/MWh.

Table 10 - DLC During 2022 Winter Storm Using Average from SEEM Data

Interrupting Time in Hours	Times per Week	Months Active	Average Hourly Consumption in kWh	Total Hours	Saved Yearly kWh Consumption	Yearly Credit	Monthly Credit	Value Being Paid by kWh	Yearly Credit (P)	Monthly Credit (P)	Value Being Paid by kWh (P)
0.275	1	12	1.2	13.2	15.84	0.87	0.072455	0.0549	0.61	0.050718	0.0384
0.275	3	12	1.2	39.6	47.52	2.61	0.217364	0.0549	1.83	0.152155	0.0384
0.275	5	12	1.2	66	79.2	4.35	0.362274	0.0549	3.04	0.253592	0.0384
0.275	10	12	1.2	132	158.4	8.69	0.724548	0.0549	6.09	0.507184	0.0384
0.275	20	12	1.2	264	316.8	17.39	1.449096	0.0549	12.17	1.014367	0.0384
0.275	100	12	1.2	1320	1584	86.95	7.24548	0.0549	60.86	5.071836	0.0384

Using this value, it becomes even more evident that we are still not at the point where a utility would benefit from using DLC from a storm. Unless the utility is in a situation where activating the program would avoid a peaker power plant needing to start operating. In that case, a DLC program would be highly beneficial. Although this is very specific to each utility's portfolio and situation.

An additional consideration arising from this study is that not all individual costs were factored into the analysis. For example, administrative costs for the implementation and operation of such a program were not accounted for. These costs, which include management, monitoring, and program coordination expenses, could potentially impact the overall cost-benefit analysis. In this study, these administrative costs were not explicitly accounted for, but might be embedded within the profit margins discussed. However, it's important to recognize that this study serves as an approximation, and future studies could explicitly incorporate and quantify these additional costs.

3. SIMULATING DLC PROGRAMS

For the second part of this study, a DLC program will be implemented on a sample grid system to analyze the impact it will have on the grid and power market. The main parameters being studied are the transmission line loads as well as the Locational Marginal Prices (LMPs) before and after the DLC program activation. The variable that will be changed for each case is the percentage of the population participating in the program and the study will evaluate the impact of each percentage level on the market price and transmission line congestions.

A concept that will be used for the modeling and analysis of this research is the virtual power plant (VPP) [73]. This same ideology can also be applied to many applications such as the battery of electric vehicles as storage devices. If there are enough electric vehicles connected to the grid, they can be seen as one large battery storage that together may have a great impact on the system. In this study, the air conditioning in each household can be seen as one small power consumption device on the grid. Similar to a virtual power plant, all the air conditioning units together can have a great impact on the grid. Instead of representing each household participating in the DLC as a separate household in which the air conditioning system is being shut down, every household attached to each bus will be represented as a single load. The activation of the DLC program will be represented by proportionally decreasing the load on the affected bus.

3.1 Related Work

There have been other studies that analyzed the impact of demand response programs, such as DLC, on the peak to average ratio (PAR) and other variables. There are multiple different algorithms to optimize the implementation of demand response programs. Linear programming (LP) and nonlinear programming (NLP) are often used depending on how the problem is formulated [74]. If the study requires the definition of each household to be defined for each time slot, other optimization programs are used such as mixed-integer linear programming (MILP) or mixed-integer nonlinear programming (MINLP). For this study, there will be a base case where the DLC program is not activated. The other cases will be evaluated at different levels of participants. Since the study will not be defining the status of each household per time slot, the script will be using LP to optimize the dispatching.

In [75], LP was used to optimally dispatch units and examine the impact of DLC programs on peak load reduction. The study created a model that can be used to find an optimal number of households that should participate in DLC programs by minimizing the number of second phase units of load control programs also considering their first phase initiation time, control duration, and payback duration. Constraints account for multiple variables, some being the load profile, phase limitations and the available control load. The model finds customer number in terms of units of control, which results in a proportion of how many customers are needed in between each of the cases. However, it does not specify the exact number of customers in each of the groups.

3.2 Script

A Python script will be used to implement DLC on a sample five bus system. The script will calculate the dispatch, flow, objective function, constraints, and other variables. The script uses an LP algorithm to solve DC Optimal Power Flow (DCOPF). This method is a highly efficient method that can be used to optimize dispatching by minimizing the cost function of generating power. This method can be used in many different applications. For example, if the cost functions of the generators are linear, the DCOPF can be solved using linear programming. If the cost functions are quadratic, he DCOPF can also be used to solve the dispatch [76].

The script used for this study uses an open-source software package called Pyomo. This package is used for different optimization techniques such as linear programming, stochastic programming, nonlinear programming, and mixed-integer linear programming [77]. For this study, Pyomo will be used to optimize the cost of dispatching each generator in a small grid system along with LP and the GLPK solver.

The program starts by reading the system data from an Excel file using the pandas library. The data includes three different sheets: Generator, Demand, and Line. For the generators sheet, the data is the name of the generator bus, the bus identifier (a letter such as "A"), the capacity in megawatts and cost in dollars per megawatt. The demand sheet contains the ID for each of the loads (it is the letter "D" and a number starting from one), the bus identifier, and the load number in megawatts. The Line sheet contains the line ID (the letter "L" followed by the bus identifier from the bus it is coming from and the bus identifier that the line is going to), the bus identifier of the bus the line is coming from, the bus identifier of the bus the line is going to, the reactance, and the capacity in megawatts. All of this data is read into dataframes and transferred to sets of objects for each sheet. The script then creates the model for the system and the dual function, which will represent the lambda used for the calculation of the price. Variables are created for the dispatch values of every generator, the flow for every line, and the theta for each bus.

The objective function to be minimized is the total generation cost, which is sum of costs for each generator according to its optimal dispatch value. Next, the constraints are created. For each bus, there is a constraint that the net power generated minus the net flow out of the bus should be equal to zero. The constraint for each line is that the flow is equal to the inverse of the reactance of the line multiplies by the difference in angles between the two buses the line is connecting. Bus A was chosen as reference, so its theta value is zero. An inequality constraint for each generator is created based on its capacity, defining that its dispatch value must be less or equal to its capacity. Using all of these variables, objective function, and constraints, the GLPK solver is used to solve for the most optimal dispatch values for each generator and the resulting price at each bus. Figure 8 shows the formulas for the objective function and the constraints created by the program.

$$
\begin{aligned}
&\min_{P_g|g\in G} \sum_{g\in G} P_g \times C_g \\
&s.t. \\
&\sum_{g|b_g=i} P_g - \sum_{d|d_g=i} P_d - \sum_{k|fb_k=i} F_k + \sum_{k|tb_k=i} F_k = 0, \forall i \in I \\
&F_k = \frac{1}{X_k}(\theta_{fb_k} - \theta_{tb_k}), \forall k \in K \\
&0 \le F_k \le \overline{F}_k, \forall k \in K \\
&0 \le P_g \le \overline{P}_g, \forall g \in G
\end{aligned}
$$

Figure 8 - DCOPF Objective Function and Constraints [78]

3.3 Bus System

The bus system and data being used to run this study is provided below.

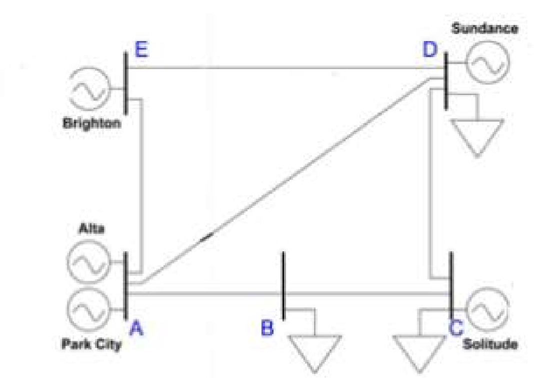

Table 1 Generator Data			
Gen Name	Bus No.	Capacity (MW)	Cost ($/MWh)
Alta	A	40	14
Park City	A	170	15
Solitude	C	520	30
Sundance	D	200	40
Brighton	E	600	20

Figure 9 - System Topology and Generator Data

Table 2 Load Data			
Time	Load B (MW)	Load C (MW)	Load D (MW)
11/20/2023 9:00	400	300	350
11/20/2023 10:00	420	315	368
11/20/2023 11:00	462	347	390
11/20/2023 12:00	508	381	413
11/20/2023 13:00	457	343	372
1/20/2023 14:00	503	377	394
11/20/2023 15:00	443	336	355
11/20/2023 16:00	421	269	347
11/20/2023 17:00	484	309	368
11/20/2023 18:00	580	371	442

Table 3 Line Data		
Line	x(p.u.)	Limit(MW)
AB	0.0281	400
AD	0.0304	
AE	0.0064	
BC	0.0108	200
CD	0.0297	
DE	0.0297	240

Figure 10 - Load and Line Data

The study will be done using the load from 11/20/2023 18:00. Since that is the highest load, it will best represent the peak hours when the DLC programs are activated. The study will decrease the load on Bus B, with the objective of alleviating the transmission line congestions on the line BC and reducing the LMP on Bus B.

3.4 Implementing DLC Using DCOPF

To simulate the activation of the demand response programs, the load will be reduced according to the number of participants in the program relative to the number of households connected to that load. This will be done at different percentages of consumer participation to represent different cases. After reducing the load, the program will be run again to find the new optimal dispatches, transmission line flows, and LMPs. The LMPs and line flows are expected to decrease. Those parameters will be used to evaluate the impact of each level of participation on the grid as well as pricing.

To define the level of decrease in load of the study that represents the current state of DLC programs, the current percentage of DR participants in the South Atlantic will be calculated. According to the 2022 Report on Demand Response and Advanced Metering, there are of 4,497,326 participants in the South Atlantic [52]. According to the Census report, there are 26,576,444 households in the South Atlantic [79]. This brings the percentage of households participating in DR programs to 16.922%. It is important to note that this value includes all of the DR programs such as time of use, real time pricing, capacity market, demand bidding, and many others as seen on Figure 1 [28]. This study will assume that a fifth of those participants are in a DLC program, which is a fair value considering that there are many other demand response programs that are more commonly used than DLC.

To find the appropriate value of load decrease to represent the activation of the DLC program, the study will approximate the number of customers under the load of Bus B. According to the California ISO, one megawatt can provide electricity for the instantaneous demand of 750 homes [80]. Using this proportion and the value of 580 MW of load on bus B, there is an estimated 435 thousand household being supplied by that load. As mentioned previously, the average air conditioning system between 3 kW to 4 kW [52]. The value to represent the load decrease when activating the DLC program is calculated using an average of 3.5 kW to represent the instantaneous power consumed by the air conditioning system of each participating household. The study will be done in four different cases. The base case will represent the grid values without the activation of the DLC program. Case 1 will have a decrease of a fifth of the total participants in DR programs in 2022, to represent the current levels of DLC programs. The other three cases represent the activation at higher representation levels, which is 10%, 15%, and 20%. Using those percentage of participants, the number of households per megawatt, the average power consumption of an HVAC system, the total load for Bus B when activating the program is recalculated. The table below shows the calculation for the load value at Bus B for each of the four case studies based on the information above. The Base Case will have a load of 580 MW, while Cases 1 through 4 will have a load of 528.359 MW, 427.75 MW, 351.625 MW, and 275.5 MW respectively.

Table 11 - Calculating New Loads for Each Case

	DLC Percentage of Participation	Full Load B in MW	Total Number of Households on Load B	Number of Households on Load B that are Participating	HVAC Power in MW per Household	HVAC in MW From All Participants	Total Load with Program Activation
Case 1	3.3984	580	435000	14783.04	0.0035	51.74064	528.25936
Case 2	10	580	435000	43500	0.0035	152.25	427.75
Case 3	15	580	435000	65250	0.0035	228.375	351.625
Case 4	20	580	435000	87000	0.0035	304.5	275.5

3.5 Results

Below are three tables for the results of this study. The first table contains the optimal dispatch value for each of the generators. The second table contains the LMP for each of the buses. The third table contains the flow on each of the lines.

When running the base case, there is a congestion on the line BC. The LMP on Bus B is also relatively high because the load on that bus can only be met by using the generation from Sundance on Bus D, which is the most expensive. By using the DLC program instead of using the generation plant with the higher cost, the LMP at Bus B is reduced. By reducing the load on bus B, the congestion is slowly relieved on the line BC.

Case 1 shows the decrease in generation of the Brighton and Sundance units, and an increase in the Solitude unit, which is significantly cheaper. This is possible due to the decrease of the generation in more expensive units. The decrease in the load on this case is still not large enough to significantly decrease the LMPs of the buses or alleviate the congestion on the line

BC. Although it does show a significant decrease in congestion on the lines AB, AE, and CD.

Case 2 showed and even larger decrease in generation of the Brighton and Sundance units, and an increase in the Solitude unit. At this level, the locational marginal prices start to drop. The price on Bus A and B dropped significantly as the more expensive units decreased generation. One anomaly seen in this case was the increase in price on Bus C. The generation unit on that us is now dispatched at its maximum generation value, therefore not being able to contribute to the LMP. This means that to supply another megawatt of energy at that bus, more expensive units must be used to calculate the LMP.

With Sundance and Brighton being the most expensive units, their dispatch is decreased as the load on the Bus B is decreased. The generation of the Solitude power plant is increasing as the load decreases, as the congestion on line BC is slowly alleviated. The price on Bus C has increased since Solitude generation plant is now operating at its maximum and is not able to meet its local load. To meet the load on both Bus B and C, some energy must come from more expensive units such as Brighton and Sundance, which increase the price at Bus C. It is important to note that although there is an increase in this specific bus, there is a more significant decrease than increase across buses. Therefore, it is still showing the effectiveness of DLC. The results from this case show the reduction in the congestion on the line BC, which was originally at its limit.

Case 3 is when the most expensive generation unit, Sundance, becomes not necessary, which is a highly favorable situation in the real world. This scenario shows that this level of participation is enough to not need the most expensive unit to be dispatched. The benefits of this case can be seen in the very significant decrease in the LMPs, especially on Bus D, where the Sundance generation unit is. There is also a very significant decrease in the congestion on the line BC, which was originally operating at its maximum limit. Something very interesting to note on this case is the decrease in price on the Bus C. It was previously increased on Case 2 and it has decreased back down to $30, which is the cost of its local generation. This is because the Solutide generation on that bus is no longer operating at its maximum. At this level of load decrease, the Sundance unit is no longer needed. Because of this, the Solitude unit starts to feed the load on Bus D, changing the net direction of the flow. This leads to a very significant decrease in LMP on Bus D.

Case 4 is as similar to Case 3 as Case 1 is similar to the Base Case. Since there are no drastic changes as to transmission line congestions or a generation unit operating at its maximum, the LMPs have stayed the same. This shows that the desired participation level is very specific to each entities' portfolio and demand. The more participation, the better, but there is in fact a point where increasing participation may not have as much effect on the LMPs anymore. This is significant in cases when the most expensive unit continues to operate when activating the DLC program, which would result in less significant impact on the grid and power market. Although this increase from Case 3 to Case 4 did not cause a change in price, it still did decrease flows and overall generation costs.

Table 12 - Dispatch Results

Dispatch	Base Case	Case 1	Case 2	Case 3	Case 4
Alta	40.0000	40.0000	40.0000	40.0000	40.0000
Brighton	574.1111	531.3678	482.6634	454.9365	441.1734
Park City	170.0000	170.0000	170.0000	170.0000	170.0000
Solitude	452.2324	510.3925	519.9999	499.6885	437.3266
Sundance	156.6565	89.4991	28.0866	0.0000	0.0000

Table 13 - LMP Results

Nodal Price	Base Case	Case 1	Case 2	Case 3	Case 4
Bus A	25.2580	25.2580	24.6601	23.4885	23.4885
Bus B	34.7185	34.7185	30.9433	28.1920	28.1920
Bus C	30.0000	30.0000	33.3585	30.0000	30.0000
Bus D	40.0000	40.0000	40.0000	34.9717	34.9717
Bus E	20.0000	20.0000	20.0000	20.0000	20.0000

Table 14 - Flow Results

Flow	Base Case	Case 1	Case 2	Case 3	Case 4
LAB	380.00000	328.25930	269.30295	235.73957	219.07945
LAD	164.11110	173.10841	183.36047	189.19689	192.09396
LAE	-334.11110	-291.36776	-242.66342	-214.93646	-201.1734
LBC	-200.00000	-200.00000	-158.44705	-115.88543	-56.42054
LCD	-118.76760	-60.60753	-9.44705	12.80311	9.90604
LDE	-240.00000	-240.00000	-240.00000	-240.00000	-240.0000

Overall, the dispatch results show that as the load on bus B is decreased, the dispatch of the most expensive units also decrease, which in this case were Brighton and Sundance. The line congestions and LMPs are also shown to decrease as the participation in DLC programs increases, especially in Cases 2 and 3 respectively.

3.6 Considerations

This study assumes that at the time the DLC program is activated, all of the air conditioning cycles are on. HVAC systems are activated for 10-to-15-minute periods and from 2 to 3 times every hour [81]. Using an average of the active time and the number of activations, there is a 52% chance that at any given point in time, the air conditioning will be activated. Since this study is ran on peak hours, this study assumed that the air conditioning of every household is currently in the active period during the activation of the DLC program. This will better represent the effectiveness of DLC programs during the time they are used.

In this case the Sundance generator can be seen as a peaker power plant. The reasoning for the high cost of that generation plant can be due to limited operation hours of the peaker power plants, as discussed above. It can also be due to other factors such as an expensive form of fuel or inefficiencies.

It is important to note that contingencies were not studied in this case. For the testing of the robustness of this system for each case, further studies including contingency analysis should be run. Another factor that was not considered is the minimum generation limits that are usually associated with each generation unit. These limits could potentially impact the results, as the inability to dispatch a generation unit at a lower value might lead to increased prices or a reduction in the overall efficiency of the DLC program. These considerations emphasize the need for further studies that account for these parameters.

4. CONCLUSION

The primary objective of this research is to examine the impact of DLC programs on the grid, the participants, and the power market. These studies provide a deeper understanding of the compensation structure for participants and the level of participation needed to improve this aspect of the power system. The two main studies run in this paper assist in the development of DLC programs to the path to a grid sustained by more renewable power.

The first study provided insights into the benefits of the consumer and the fairness of the compensation structure of three different DLC programs from utilities in Florida. TECO was found to be paying customers three times less than their own valuation of the kilowatt prices at times when demand charges are made. These valuations were expected to be more similar, since the DLC program could be used interchangeably. FPL and Duke were found to be paying a very fair price to its customers. This should be seen as an incentive for consumers to participate in the program now since the utilities are already paying customers a fair price. With the increase in participation, the utilities will have much higher ability to use the program and gain benefits as well as provide them.

The second study successfully implemented the activation of DLC programs on a sample five bus system. The results showed that as the participation on DLC programs increased, the LMPs and the congestion on transmission lines both decreased. One important observation from this study is that the main changes occurred when an expensive unit was no longer needed to meet the load. In the real world, this will highly vary between utilities depending on their portfolio, costs, and demand. In this case study, Case 3 showed the most benefits since it was the point when the most expensive unit was no longer necessary. This caused the most impactful decrease in LMP.

Future studies associated with the analysis on the second chapter of this paper should include other costs associated with DLC programs such as administrative costs. This will represent the more detailed costs associated with the program. Future studies similar to the third chapter of this paper should include the start up and shut down costs associated with peaker units, contingency analysis, and minimum generation limits. The start up and shut-down costs will assist with the representation of the peaker power plants. Running a future contingency analysis will provide more insight into the robustness of the grid, as well as the benefits that DLC programs can provide in case of an outage. Minimum generation limits could also assist with the modeling of this program, since it would allow for better representation of real-world conditions and limitations.

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