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The size, causes, and equity implications of the demand-response gap

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ABSTRACT

Our analysis of policy options was motivated by an inexplicable under-investment in demand response (DR) in the U.S. state of Georgia. In addition to estimating the size of the DR gap, we identify its causes and consequences. By modifying parameters of the U.S. flagship National Energy Modeling System (NEMS), we generate a baseline DR forecast with a default 4% maximum on-peak demand reduction, an achievable case with a DR limit of 20%, and a technical scenario that also halved the cost of storage. The results document many benefits of DR including a demand-reduction induced price effect (DRIPE), which makes DR more equitable than many other clean-energy policies that shift costs to non-participants. Our modeling results, literature review, and focus group analysis enable identification of DR barriers and motivators related to financial costs, electricity rates, consumer bills, pollution emissions, public health, energy equity, and inclusion. Our results suggest that the DR gap is caused less by technology limitations than by the need for financing initiatives, market innovations, infrastructure modernization, and enablers of socio-economic inclusion. By studying a state that lags in DR implementation, other countries and sub-national entities where DR is under-utilized can learn from our findings and methods.

1. Introduction

In many regions of the U.S., electricity systems are being strained by four trends. The grid is expanding its intermittent renewable resources, transportation and buildings are electrifying, coal-fired generation is increasingly being retired, and distributed energy resources are proliferating. The result is a challenging era for the orchestration of power management. Hence the renewed interest by policymakers in the potential value of expanding demand response (DR) programs and supporting policies.

As these trends continue, flexible demand becomes increasingly valuable. By investing in advanced metering infrastructure, direct load control programs, incentive payments, and dynamic pricing, demand responsiveness can be strengthened. A traditional focus is demand reduction during the utility's peak hours, when wholesale prices are high or when supplies are interrupted by severe climate or other contingencies. With the direct load control of heat pumps, water heating, air conditioning, and electric vehicle (EV) charging, power providers can enhance system reliability and resilience. Such DR approaches are analogous to providing decentralized energy storage.

Technological innovations that enable responsive demand have spurred wholesale markets to incentivize DR to participate. As a result, system aggregators are increasingly engaging smaller entities including residential markets, extending beyond their initial focus on commercial and industrial markets. Many believe that DR can reduce daily peak loads and contribute to system reliability, while also decreasing the cost of supplying electricity services and reducing greenhouse gas (GHG) emissions (Smith and Brown, 2015). The vision is that with modern technology, DR can turn off water heaters, cycle air conditioners, postpone electric vehicle charging when system peaks threaten reliability, when a gas plant is tripped, or when clouds block local solar panels; its applications are only limited by our imaginations. As one example, when power prices in Texas exceeded $200/MWh, a crypto-currency company powered down its data operations for 30 min because they could make more money selling electricity back to the power company, and the power company could balance its load cheaper by paying them to drop their load (Martin, 2020).

In 2021, the "Drawdown Georgia" research team from three universities completed a study to determine the role that various carbon reduction approaches could play to effectively reduce the GHG footprint of the U.S. southeastern state of Georgia. We began by evaluating Georgia's baseline GHG footprint and trends, assessing 100 carbon-reduction solutions that could be impactful by 2030, quantifying their potential as solutions for Georgia, and considering associated costs and

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benefits such as job creation, public health, waste streams, and equity. DR was identified as one of 20 high-potential opportunities down-selected from a list of more than 100 solutions (Brown et al., 2021).

A detailed assessment of DR was then launched, motivated by the inexplicable lack of investment in demand response policies and measures in Georgia. A review of the literature on market and technology transformations, stakeholder analysis, organizational theory, and barriers to innovation suggests the hypothesis that the DR gap is caused less by technology limitations than by the need for financing initiatives, market innovations, infrastructure modernization, and enablers of socio-economic inclusion.

To explore this hypothesis, we begin by describing the current status of DR in the U.S. and in Georgia (Section 2). We then describe the methodology used to estimate the magnitude of the DR gap, relying on the National Energy Modeling System (Section 3). By comparing a baseline forecast with achievable and technically feasible potentials for DR, we are able to determine if there indeed is a gap in investment in DR in Georgia. Section 4 describes the results, including an assessment of the shift in fuel mix, utility costs, energy prices, utility bills, and carbon emissions. Section 5 discusses these results in terms of the barriers and challenges that confront DR, and the tools and policy solutions that can overcome them. The paper ends with a set of conclusions about DR and the policies needed to expand its role in carbon mitigation.

2. The current state and recent trends in demand response

DR programs are often characterized as either price- or incentive-based (Durvasulu et al., 2018; Ho et al., 2018; Parrish et al., 2019). Under price-based DR, customers are exposed to time-varying rates to which they are expected to adapt their demand. Price-based DR is administered by local power companies primarily to residential and commercial participants, and participation has been growing with the expansion of dynamic pricing and access to advanced metering (FERC, 2019). Incentive-based DR rewards consumers for estimated changes in demand compared to a baseline level of electricity use. To assess their impact on production costs, generation mix, prices, bills, and carbon emissions, it is useful to distinguish between programs that focus on peak-load reduction vs peak-load shift. Incentive-based programs such as critical-peak rebates, direct-load control, and interruptible/curtailable programs focus primarily on peak-load reduction (Durvasulu et al., 2018; Ho et al., 2018). The same is true of market-bidding programs for demand, capacity, and ancillary services (Durvasulu et al., 2018). In contrast, price-based programs such as static time-of-use programs (where prices change at pre-determined times) encourage peak-load shift as well as peak-load reduction (Parrish et al., 2019).

2.1. DR technologies and policies across the U.S

Today's DR is being transformed by technology and market innovations: smart-grid technologies, dynamic pricing, and advanced meters enable faster and better control of demand-side resources. Advanced meters measure and record usage data in hourly or smaller intervals, sending usage data to energy companies and consumers (USEIA, 2019). They can also record and transmit instantaneous data by adding built-in two-way communications, enabling real-time metering and measurement. Advanced meters now account for 52% of all meters in the U.S., up from 4.7% in 2008 (FERC, 2019).

DR has been used extensively in industrial and commercial sectors since the 1970s, and today it is the largest distributed energy resource (DER) in the U.S. – larger than the backup power provided by batteries, the magnitude of charging demanded by electric vehicles, and the capacity of rooftop solar systems (Faruqui and Hledik, 2018). FERC (2019) estimates that the U.S. could reduce its peak demand by 31.5 GW using retail demand response programs in 2017. In comparison, only 12.2 GW of demand response was called and saved in 2017 (FERC, 2019). The Brattle Group (2019) estimates that the U.S. potential for load flexibility could be even more substantial, totaling approximately 200 GW by 2030, with the most significant cost-effective potential from dynamic pricing programs across all customer classes along with residential smart thermostat programs.

Across the nation's 11 reliability regions, the Southeast region ("SERC") accounts for the highest portion of DR potential, at 8.8 GW (FERC, 2019, Table 3–1). In contrast, SERC is fifth among the 11 regions in the number of customers enrolled in DR programs in 2017. The Southeast portion of SERC (SERC-SE) is forecast to account for 35.9% GW of SERC's peak demand in 2023 (FERC, 2019). Based on this apportionment, the SERC-SE technical potential for DR would be approximately 3.2 GW of the SERC total (8.8 GW), and Georgia Power would be 46.2% of that total or 1.48 GW.

The gap between the potential and actual peak demand savings illustrates the shortfall in applying demand response across the country. A 2020 landmark FERC Order No. 2222 seeks to remove barriers to wholesale market participation of demand response and other distributed energy resources (DERs). It is unclear how much this new Order will incentivize DR, but the Order is an indication that federal regulators believe the market signals for DR are not operating effectively (Endemann et al., 2020).

2.2. DR technologies and policies across Georgia

The state of Georgia's largest electricity service provider, Georgia Power, offers DR programs to its residential and large commercial and industrial (C&I) customers. When first introduced nearly 20 years ago, Georgia Power had one of the country's most extensive C&I DR programs. Braithwait and O'Sheasy (2002) analyzed data from its participants and found that the most responsive customer segment was a group of large industrial customers (peak demand >5 MW) who, in exchange for slightly lower base rates, had opted to receive notification of hourly prices on an hour-ahead basis. This group exhibited a price elasticity of demand of −0.18 to −0.28 across the range of reported prices, which was twice the elasticity of any other group. Conversely, the least responsive customer segments, consisting of smaller C&I customers that neither had onsite generation nor had previously participated in the utility's curtailable rate, exhibited price elasticities of −0.06.

Based on the latest Georgia Power (2019) Integrated Resource Plan, Georgia Power's DR capacity is forecast to grow to 1.6 GWs (40% passive demand-side management, 60% active demand response) by 2022, which is 5.2% of its current generating capacity. One involves direct load controls (DLC) and the other two provide incentives to participants. All of these proposed new DR programs and pilots promote smart thermostats (Georgia Power, 2020):

- The Residential Thermostat Demand Response Program is a stand-alone DR program that promotes home energy efficiency improvements to shift electricity usage from peak to off-peak demand periods. To achieve this goal, Georgia Power will install a free smart thermostat, or it will provide financial incentives for customers with existing smart thermostats so that Georgia Power can manage their HVAC loads during demand response events.
- The Home Energy Improvement Program provides rebates and contract support for home energy improvement work, including smart thermostats.
- The new Residential Income-Qualified Program is a program through which Georgia Power will provide up to $2,000 for 500 homes to provide retrofits and services related to HVAC systems. One offering through this program is the direct installation of energy-efficiency measures, including smart thermostats.
- DR is also a feature of Georgia Power's Smart Neighborhood pilot project called "Altus at the Quarter," which includes 46 townhomes located in Atlanta. This pilot involves the grid integration of solar panels and battery storage, smart management of heat pumps and water heating, and electric vehicle (EV) charging – a combination of

initiatives that can significantly reduce peak consumption (Ingram, 2020). It is a first-of-a-kind demonstration project in Georgia (ETEC, 2020).

Additionally, for nearly a decade, Georgia Power has had a time-of-use (TOU) program that offers alternative rates for on- and off-peak electricity use during summer months (June–September), excluding holidays. When enrolled, customers are charged ~20.32¢ per kWh during on-peak and 4.98¢ per kWh during off-peak hours (Georgia Power, 2021a). This price variation encourages consumers to shift some summer energy usage away from the on-peak periods (2–7 p.m., Monday–Friday). More recently, TOU rates have been extended to plug-in EV charging with on- and off-peak rates at 20.32¢ and 6.68¢ per kWh in addition to a super off-peak (11 p.m.–7 a.m. all year round) rate of 1.44¢ (Georgia Power, 2021b). However, according to the USEIA (2020), by 2018 only 18,000 of 2,200,000 (0.8%) of residential Georgia Power customers had enrolled in the available dynamic pricing options compared to 2.2 million (3.4%) nationally.

With the launch of these new initiatives, and now that most Georgia Power customers have a smart meter, Georgia Power is in a strong position to expand its DR program participation. To illustrate the achievable potential, we consider the opportunity to better manage the demand for residential water heating and space conditioning with DLC programs.

Water heaters are a crucial component of electricity use in the residential sector. Approximately 70% of the water heaters in the Southeast U.S. use electricity as their fuel source (Ryan et al., 2010). Demand response programs can reduce the electricity demand from water heaters by either DLC or pricing policies. Based on an engineering analysis, Qaseem et al. (2020) estimated that DLC has a DR potential of 300 MW in the winter and 180 MW in the summer for Georgia. On the other hand, dynamic pricing programs have far less demand reduction potential, with only approximately 25 MW and 15 MW reduction in the winter and summer, respectively. Underpinning these estimates is the assumption that approximately 20% of customers would be willing to enroll their water heaters in a DLC utility program (Faruqui, 2012).

There is growing evidence that smart thermostats could benefit households in Georgia. The average Georgia household uses approximately 7 kW of maximum demand. The average annual reduction in peak demand for a single-family household under Georgia Power programs is 0.43 kW per participant. Nationally, the range is 0.6–1.2 kW per participant (Gagnon et al., 2017), placing Georgia on the low-end of demand savings per participant. In contrast, Georgia is on the high end in terms of the level of participation – with approximately 72,000 households or 3% of Georgia's residential customers (and 8% of its single-family customers) predicted to have smart thermostats in 2020 (Georgia Power, 2019). Qaseem et al. (2020) estimates the potential savings and costs from smart thermostats installed in single-family households enrolled in Georgia Power programs in 2020. The authors assume a load-shift of 86 h per household per year. Multiplying 86 by the demand savings-per-unit and by the number of participating households results in a total of 2.56 MW of demand savings**,** resulting in a total reduced cost to the utility of $20.21 million**.**

Heat pumps have historically been targeted for demand response management, and the recent addition of variable speed models enables even greater grid flexibility (Tang, 2021). While traditional HVAC units with one or two stages typically require minimum run times at each stage for equipment longevity, variable speed heat pumps allow for more frequent adjustments of power levels, enabling better load following of fluctuating grid supplies (Feldhofer, 2021).

Further electrification of Georgia's household enegy use could magnify the impact and equitable coverage of DR programs. Nearly half (43%) of Georgia households, and an even higher percent of low-income households heat their homes with natural gas and are therefore unlikely to participate in DR programs (USCB, 2019). Subsidizing the electrification of home heating as well as water heating would address the equity issue of lower-income households being disproportionately excluded from potential DR programs (Rose, 2020).

Power Credits, a form of DLC through cycling HVAC systems on and off, has also been shown to have considerable potential for clipping peak energy demand and lowering consumers' overall electricity consumption. As implemented in a Texas pilot program, the program cuts demand by paying eligible customers a $2 credit per cycle during peak central cooling use. Qaseem et al. (2020) applied the Texas pilot findings to assess the potential for such a program implemented in Georgia, assuming levels of penetration ranging from 10% to 30% of households and ten cycles during peak demand (2–7 p.m. on summer weekdays from June to September). The yearly DLC impact of a Power Credit Program in Georgia is estimated to range from a 0.7–3 GW reduction in consumption.

In sum, past experience with DR programs in Georgia and nearby states suggests opportunities for cost-beneficial expansion. Further, today's DR may be less challenged by technology gaps than by the need for more supportive rates, program designs, and business models (Walton, 2020). We now turn to an assessment of how different stakeholders might evaluate such opportunities.

2.3. The risk and reward structure of demand response

Market and technology transformations have the potential to reward organizations associated with the supply chains of incoming technologies. At the same time, they can place constituents supported by the incumbent system at risk. To clarify impacts such as these, it is valuable to array stakeholders within a dimension ranging from "risks" to "rewards." Stakeholders driven by the prospect for rewards might be motivated by positive outcomes such as financial returns on investment, market leadership development in an emerging field, or motivation by an aligned vision or organizational purpose. On the other hand, stakeholders dominated by a concern for the risks might be preoccupied with the fallout resulting from a technology transformation, such as economic costs, loss of market share political difficulties, or adverse reputational effects (Johnstone and Kivimaa, 2018). Since a single stakeholder could anticipate an array of risks and rewards, each stakeholder position may represent a range or summation of risks and rewards. For example, a local power company might see value from the reduced costs of clipping the peak demand of customers but might also be concerned about the possibility of load reduction resulting in a loss of electricity sales.

When stakeholders are strongly driven by the anticipation of rewards and have the capacity to exert significant influence, they can become powerful champions of a transformation (Geels et al., 2017; Winskel, 2018). Fig. 1 suggests the possible position of key stakeholders on a risk-reward spectrum and identifies some of them as possible champions of DR programs, policies, markets, and supply chains. It benefited from a facilitated focus group discussion of demand response that engaged approximately 20 Georgia experts from a broad range of backgrounds in the public, private and non-profit sectors.

With the Biden Administration's appointees now in place, environmental justice is moving to the forefront of agency action and policy. EPA defines *environmental justice* as "the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income concerning the development, implementation, and enforcement of environmental laws, regulations, and policies" (USEPA, 2021). The fairness of DR programs is challenged by the many barriers to participation faced by low- and moderate-income households, including financial constraints, split-incentives, aging and non-electric appliances, and internet connectivity (Calver, 2021).

Many low-income households are renters, and renters often lack control over the type of appliances installed in their residences. There is also the problem of "split incentives," where landlords own the large appliances and thermostats and pay for upgrades, but tenants receive most of the benefits. As a result, landlords are not motivated to invest in efficient or smart appliances (Brown et al., 2021; Xu, 2019). Therefore,

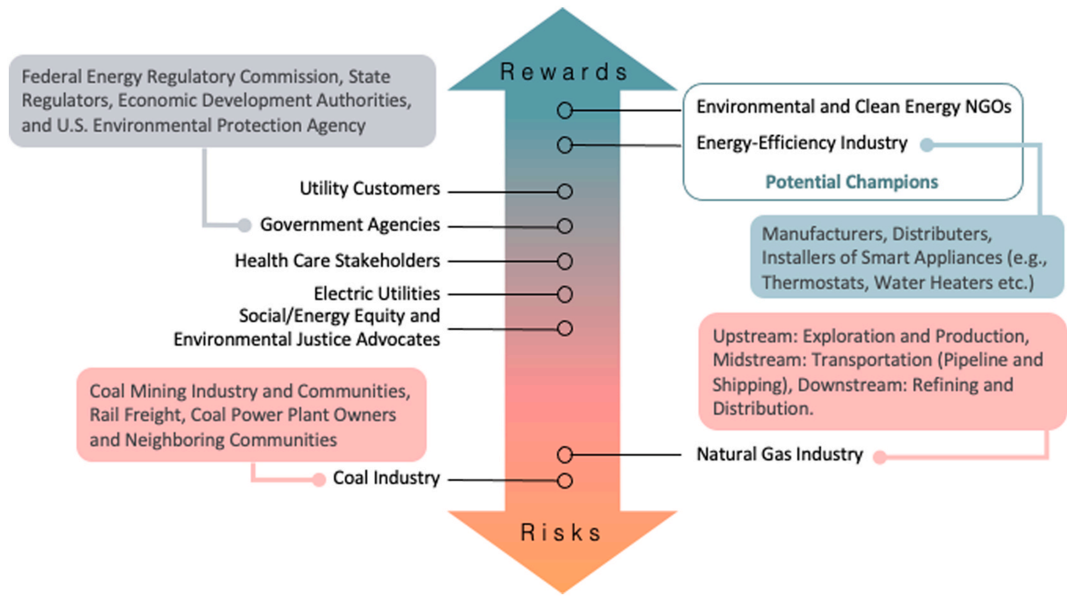

Fig. 1. Stakeholder Analysis for Demand Response.

Reduced peak demand allows utilities to cut more costly forms of generation such as coal. As a result, stakeholders of the coal industry do not typically support demand-side management programs. Note, however, that most of the stakeholders shown in Fig. 1 would appear to benefit more from the rewards than the risks of DR. Thus, it is likely that uncertainties about the potential impacts of expanding DR are hindering market expansion. The following analysis aims to clarify the potential impacts of DR by conducting a case study of the Southeastern U.S. state of Georgia.

both income level and being a renter are inversely related to the number of energy-efficiency features at home, including ownership of Energy Star products and home insulation (Pivo, 2014; Brown et al., 2020). As of 2009, multifamily units occupied by low-income renters had 4.7 fewer energy-efficiency features than medium and high-income households (Pivo, 2014). As a result of these disparities, environmental justice advocates are concerned about the ethical risks of traditional DR programs. In contrast, public interest groups focusing on the environment and green energy emphasize the clean air and climate benefits of DR programs. Similarly, health care stakeholders are also supportive of DR and energy-efficiency programs, based on the public health benefits that result from clean air and more affordable utilities, which lower costs for hospitals and insurance companies (Brown et al., 2021).

While participation in DR programs is primarily limited to homeowners, demand-reduction induced price effects (DRIPE) should not be overlooked. DRIPE savings accrue not only to participating customers who consume less through DR programs but also to non-participating households whose energy bills decline as a result of lower prices (Baer et al., 2015). DRIPE savings, though seemingly small in terms of percentage price reductions or dollars per household, have the potential to amount to hundreds of millions of dollars per year across entire states or grids (Taylor et al., 2015). The DRIPE effect makes DR more equitable than many other clean-energy policies that shift costs of clean technology adoption to non-participants.

3. Methodology for modeling Georgia's DR potential in 2030

To span the range of possible future scenarios for demand response, we specify three scenarios: the baseline forecast, and the achievable and technical potential. The strategic analysis of carbon reduction options often uses concept of business-as-usual forecasts, technically possible limits, and achievable possibilities that fall between them (Brown et al., 2001; Brown et al., 2021). While many analysts focus on mid-century technology transitions, we chose to focus on 2030, since climate science indicates that actions in the near-term are needed to meet science-based climate goals (Brown et al., 2021).

All three scenarios are modeled using the 2018 version of the National Energy Modeling System (NEMS) run at the Georgia Institute of Technology (GT-NEMS). NEMS is the U.S. flagship modeling system used to make projections for the U.S. Energy Information Administration's Annual Energy Outlook since 1994 (USEIA, 2018). It is a partial equilibrium model with macroeconomic feedback: each of its 10 end-use, conversion, and supply modules finds its own partial equilibrium solution balancing supplies with demands, and a macroeconomic module provides mechanisms for incorporating economy-wide impacts of these solutions back into the modules (Arora et al., 2018). NEMS is documented in a series of model documentation reports, available on the EIA website and summarized in USEIA (2018). Because of its complexity, few organizations other than the USEIA use the developer's version of NEMS to modify input files and codes, allowing alternative assumptions to be explored, as is the case in our analysis of demand response. Specifically, we modify the Electricity Market Module (EMM).

EMM models U.S. electric power systems through a regional planning approach with four constituent sub-modules and 22 (in 2018) to 25 (in 2021) planning regions defined by the North American Electricity Reliability Corporation. In computing estimates of cost-minimizing supply choices, inputs are used to characterize end-use load shapes, costs and performance of capacity types, and other key variables. EMM performs separate projections of power demand and the cost-minimizing supply necessary to meet that demand for each region. One of these regions is called SERC-SE. It represents the service territory of the Southern Company, which is the load-balancing authority for virtually all of the state of Georgia and a majority of Alabama. We use historical data to proportion activity levels from SERC-SE to Georgia.

DR is dispatched in EMM by transferring load from peak periods to non-peak periods when it is cost-minimizing to do so. To facilitate the complexity and scale of its computations, it uses a simplified load duration curve that is divided into season-types – summer, winter, and "shoulder" (i.e., spring and fall). These seasons are in turn separated into three time slices: peak, intermediate, and off-peak. The peak period of each season is defined as the season's top 29.3 h of system load. GT-NEMS allows DR to decrease load only during the peak demand periods – the top 88 h of the year – and energy saved during those periods is shifted to intermediate or base load periods. See Smith and Brown (2015) for further details about EMM and see Appendix A for further description of our modeling approach.

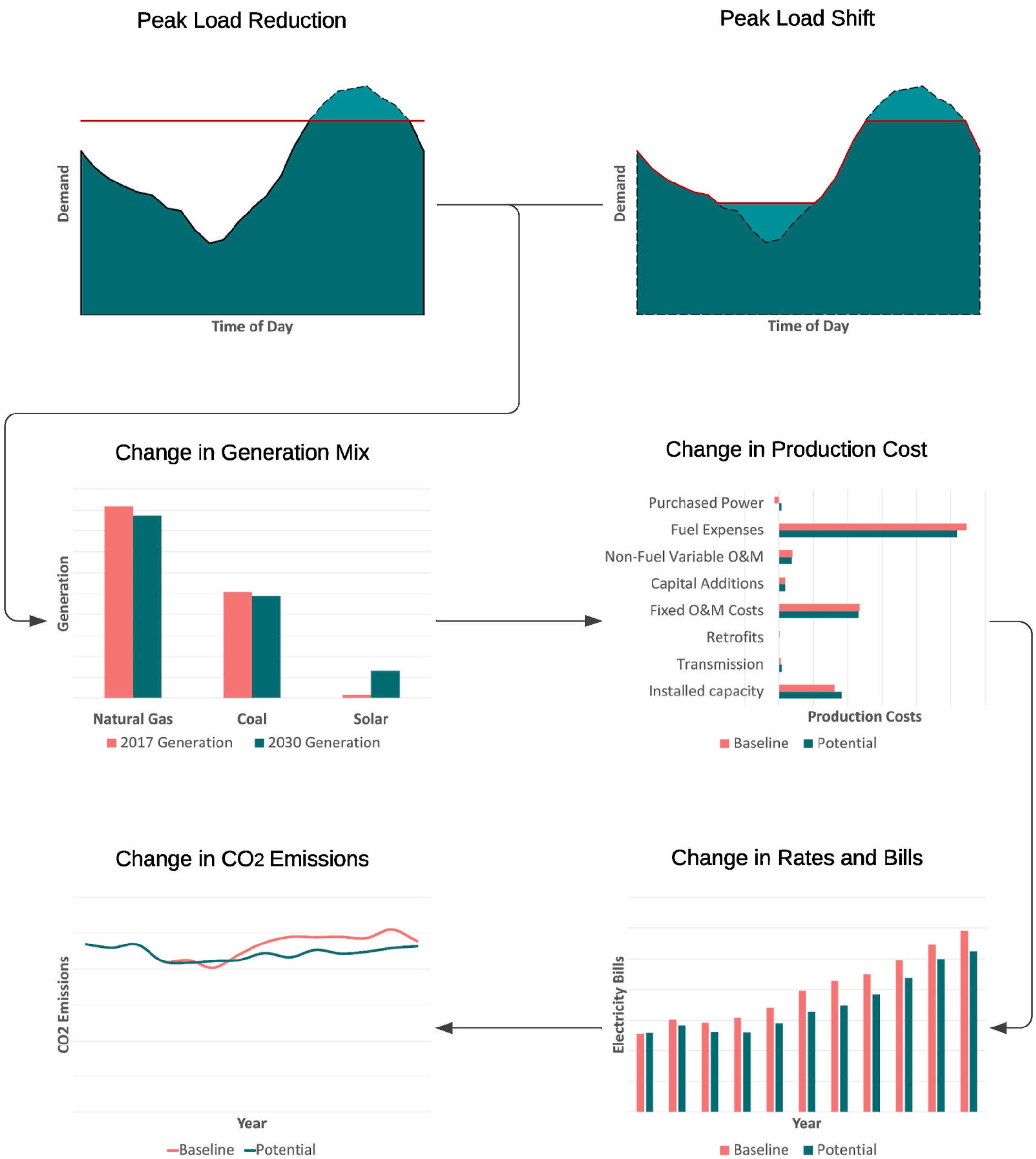

Fig. 2. Logic and coverage of research design.

Modeling the Baseline Forecast for DR. The baseline forecast modeled in GT-NEMS assumes that beginning in 2020, only 4% of the SERC-SE peak load can be shaved or clipped. This parameter acts as an upper limit on the capacity of DR resources that can be constructed in the region. In addition, the baseline forecast assumes that 96% of off-peak generation must be delivered to compensate for each unit of on-peak load reduction from DR. These are the assumptions used in EIA's Annual Energy Outlook published in 2018 and subsequently through 2020. If the on-peak electricity that is clipped in 2030 is equal in carbon intensity to the Georgia grid's average generation in 2030, then the demand response programs in the baseline forecast would not impact carbon emissions. If it is more carbon-intensive than the grid average, then the DR programs in the baseline are forecast to contribute to the declining carbon intensity of Georgia's grid. In any event, this impact is limited by the NEMS baseline constraint that DR cannot reduce peak demand by more than 4%.

Modeling the Achievable Potential for DR. The achievable potential for DR is modeled by increasing the allowable reduction of demand during the 88 on-peak hours to a maximum of 20% between 2020 and 2030, compared to the 4% maximum used in the baseline forecast. In essence, it is assuming that the capacity of DR resources is five times larger than in the baseline forecast. With this new capacity, the electricity consumed during the 88 on-peak hours can be reduced by 20%, and 96% of any peak-load reduction must be compensated by increased consumption during off-peak hours.

Modeling the Technical Potential for DR. The more substantial technical potential for DR build on the achievable scenario by assuming the same expanded capacity of DR resources to a maximum of 20% between 2020 and 2030. In addition, GT-NEMS is modified to reduce the assumed cost of storage in 2030 by 50% compared to the 2030 baseline forecast. For overnight capital cost, for example, the technical potential assumption is that storage would cost $1,236/KW in 2030 instead of $2,475, which is the assumption in the baseline forecast and the achievable scenario. In comparison, Lazard (King, 2018) forecasts that storage costs in 2030 will be $989/and Bloomberg New Energy Finance (2018) forecasts $268 (See Table A1 for further details.). By forecasting lower storage costs, the potential DR resources modeled in the achievable scenario will be more affordable, which should cause more of them to be selected in the Electricity Market Module.

The outputs from GT-NEMS, combined with additional indicators and estimates from the literature, enables us to quantitatively assess the impact of DR on a range of outcomes, including production costs, generation mix, electricity rates and bills, and the emissions and public health impacts of various pollutants including CO_2, SO_2, NOx, PM2.5 and PM10. The logic and coverage of the research design is summarized in Fig. 2.

4. Results

We begin by estimating the impact of DR on Georgia's electricity fuel mix. We then characterize likely consequences for utility resource costs, rates, energy consumption and energy bills. This section ends with a description of impacts on pollution and public health.

4.1. The impact of DR on fuel mix

According to S&P data, SERC-SE generated 254,000 GWh of electricity in 2018, and Georgia Power Company produced 104,000 GWh (40.9%) of this total. In the same year, SERC-SE had 66 GWs of generating capacity, with 30.5 GW (46.2%) of this total owned by Georgia Power Company.

In the GT-NEMS baseline forecast, the total generation is expected to grow by 13.3% (from 95.4 to 108.1 BkWh) from 2017 to 2030. Nuclear expands significantly, and solar also grows. In the achievable and technical scenarios, total generation would grow by only 11.5%, with lower levels of coal and natural gas generation and higher levels of utility solar under the technical scenario (Fig. 3).

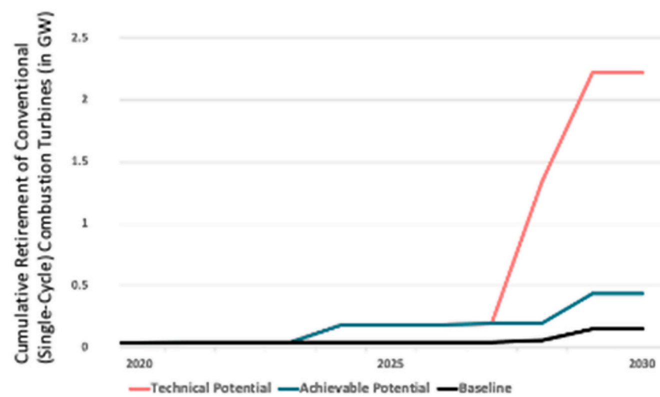

Fig. 4. Retirement of conventional combustion turbines resulting from increased demand response.

In the GT-NEMS baseline forecast, only 1.29% of conventual combustion turbine capacity would be retired by 2030. This increases slightly to 3.81% of capacity retired under the achievable potential scenario, while the technical potential scenario portrays a substantial 19.36% capacity retirement by 2030 (Fig. 4). GT-NEMS specifies that several single-cycle oil and gas turbines would be retired permanently with significant uptake in demand response.

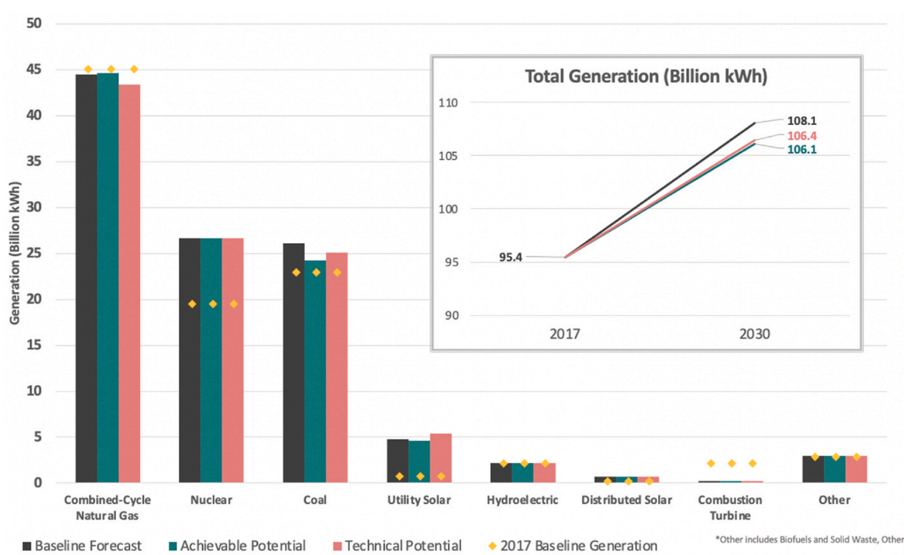

Fig. 3. Electricity Generation Mix in Georgia in the Baseline Forecast and Two Demand Response Scenarios (Source: GT-NEMS modeling results. Note: Other includes Biofuels and Solid Waste, Other Distributed Generation, and Storage Options).

4.2. The impact of DR on production costs

In this section, we characterize the utility resource costs required to realize Georgia's achievable and technical potential for demand response. GT-NEMS estimates the utility production system costs associated with meeting electricity demand in the baseline forecast and alternative scenarios. We assume that 46.2% of these costs in the SERC-SE region are associated with managing the electricity system in Georgia. Comparing costs across the achievable and technical scenarios identifies how different types of utility costs might be affected. Eight components of utility resource costs are presented in Table A5 and are summarized in Table 1.

The estimated utility resource cost of Georgia's baseline system starts at $4.73 billion in 2020 and rises to $4.79 billion in 2025 and $4.97 billion in 2030. Fuel expenses, fixed O&M costs, and the cost of expanding the system's capacity are the three largest cost components.

In the two alternative scenarios, production costs are highly variable year-to-year. In 2025, the least-cost approach to implementing the achievable scenario in Georgia would cost an additional $28 million – an increment of less than 1% due to more substantial costs for installed capacity and transmission costs. Delivering the technical scenario in 2025 would cut utility resource costs by $32 million – a savings of less than 1% due primarily to lower fuel expenses.

In 2030, the utility resource costs associated with both the achiev-

Table 1
Utility resource costs: 2020, 2025, and 2030.

	Annual Utility Resource Costs (Billion $)			Difference from Baseline Forecast (Million $)		Cost per Avoided CO_2 ($/t$CO_2$)		
	2020	2025	2030	2025	2030	2025	2030	Average
Baseline Forecast	4.73	4.79	4.97	–	–	–	–	
Achievable Scenario	4.73	4.81	5.02	27.80	52.92	10.90	27.14	6.11
Technical Scenario	4.76	4.75	5.01	−32.34	47.04	−5.05	28.68	5.38

Note: All costs are presented in $2017.

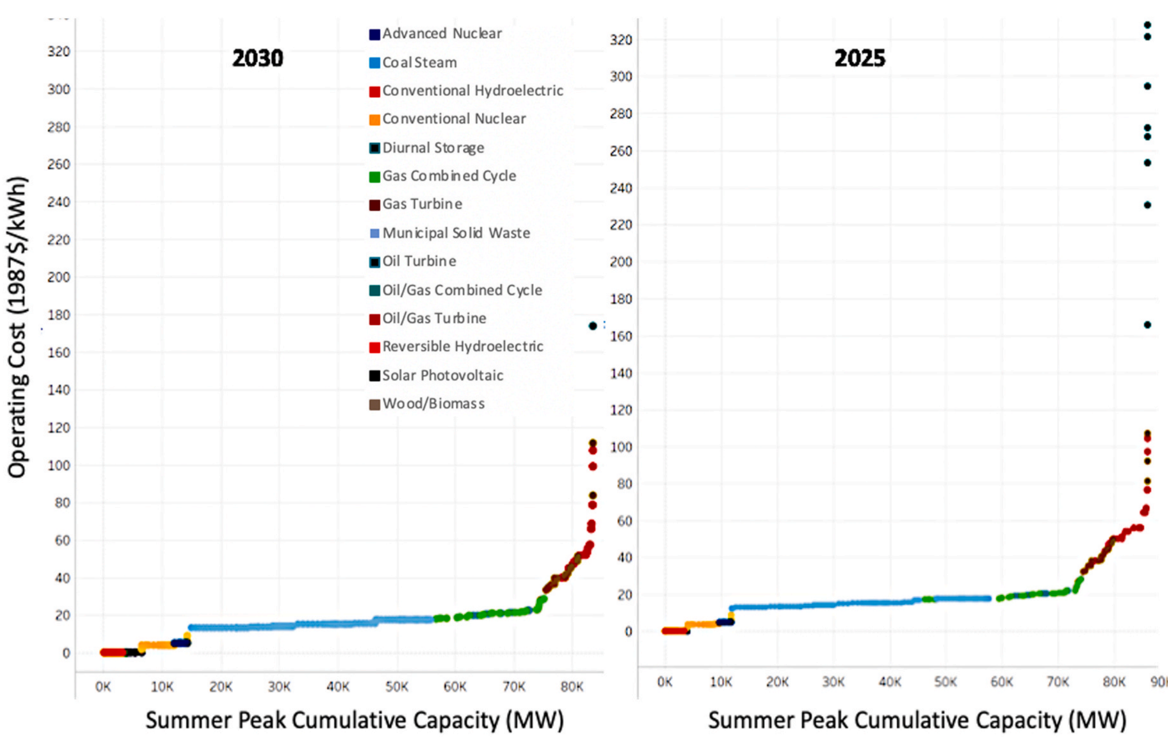

Fig. 5. Bloomberg New Energy Finance (2018) Summer Electricity Dispatch Curve for SERC-SE Region in 2025 and 2030 (Source: GT-NEMS modeling results).

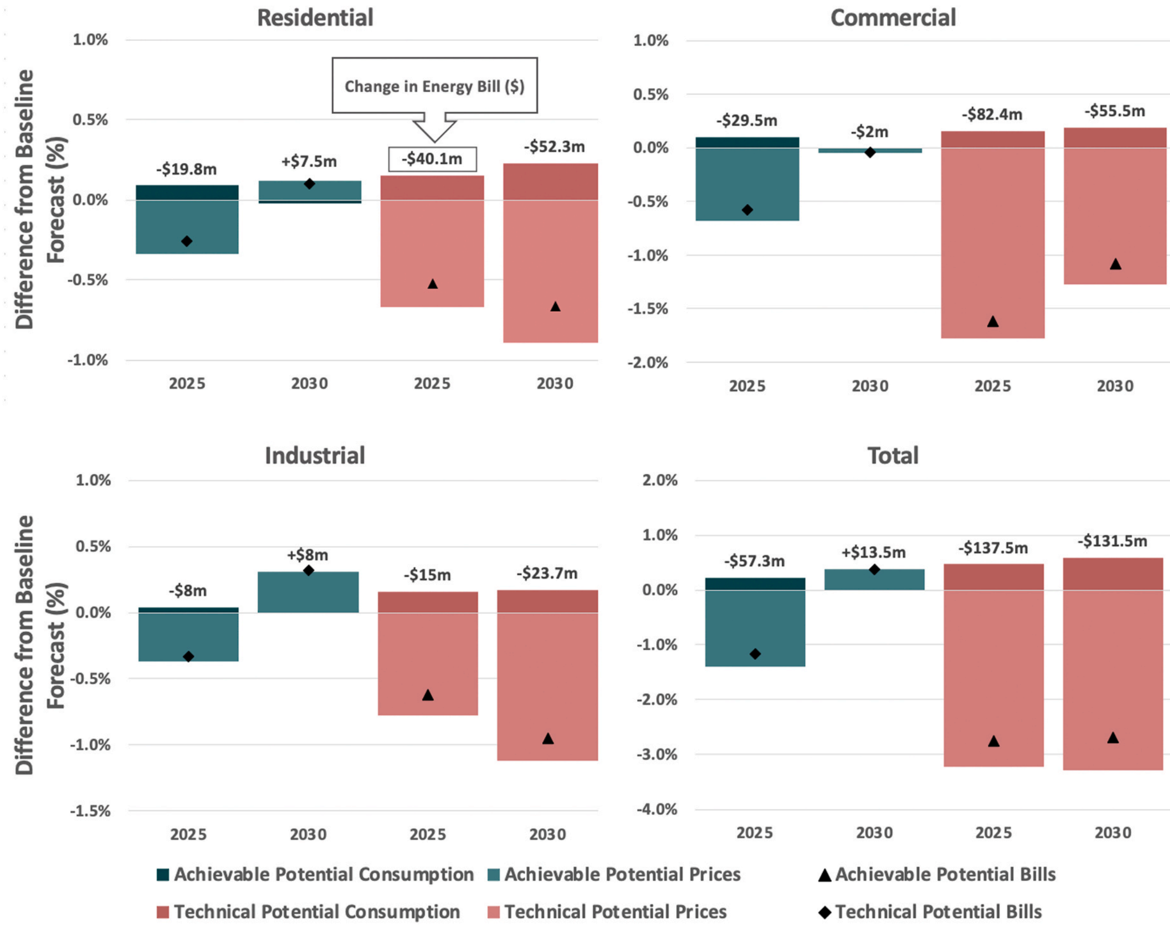

Fig. 6. Impact of DR on electricity consumption, prices, and bills.

able and technical scenarios are larger than in the baseline forecast. Investments in installed capacity and transmission account for the majority of the additional expenses while fuel expenses continue to provide the greatest source of savings.

When divided by the resulting levels of avoided CO_2, the costs range from -\$5 to \$11 million/tCO_2 in 2025 and from \$27 to \$29/tCO_2 in 2030. As costs fluctuate across years, the average costs across the decade were also calculated and ranged from \$5 to \$6/tCO2. In sum, realizing the achievable and technical potential for DR triggers <1% increase in costs, and sometimes reduces costs.

Fig. 5 shows the significant operating cost incurred in the SERC-SE region in 2025 and 2030, to meet the highest hours of on-peak summer demand–these are the hours that demand response programs target. During these periods of peak demand, electricity from single-cycle diesel, oil, and natural gas turbines are added to the generation mix. These dispatch curves suggest that implementing demand response during peak summer hours would cause the displacement of expensive and polluting generation. In their earlier national assessment, Smith and Brown (2015) also found that DR can result in the retirement of significant amounts of expensive, aging peak capacity such as single-cycle natural gas and petroleum combustion turbines, similar to those identified in Fig. 5.

4.3. The impact of DR on energy prices and bills

Changes in utility resource costs, in turn, can influence energy prices, consumption, and bills. We focus on electricity and natural gas prices and bills, since other fuels are used sparingly by households and businesses in Georgia. Fig. 6 illustrates the changes in electricity bills for Georgia households and commercial enterprises under the two DR scenarios. Lower electricity rates and bills are forecast economy-wide in both scenarios. (See Table A4 for further details.)

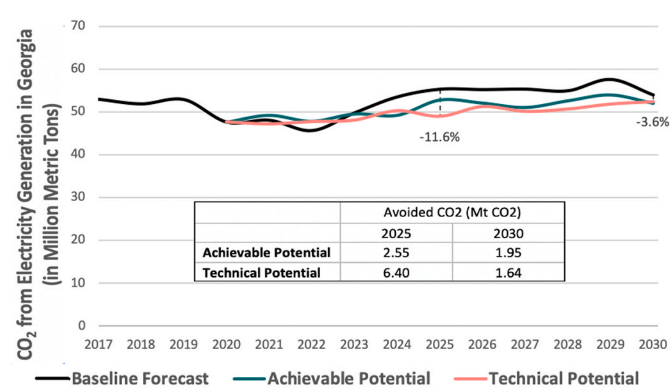

Fig. 7. Potential for Carbon Drawdown from Demand Response in Georgia in 2030, in Million Metric Tons of CO_2 (Source: GT-NEMS modeling results, Table 245, Row 156).

In the baseline forecast, residential electricity prices are expected to increase from 11.97 ¢/kWh in 2017 to 13.35 ¢/kWh in 2030. In both the achievable and technical scenarios, electricity rates diverge slightly from the baseline rising to 13.37 ¢/kWh and 13.23 ¢/kWh respectfully by 2030. Between 2020 and 2030, both achievable and technical scenarios see rates increasing, on average, at 0.15% and 0.51% lower than the baseline. The greater the DR, the greater the rate decrease. Natural gas rates see no statistically significant changes between the baseline and the achievable and technical scenarios.

A slight increase in overall consumption partially offsets the decrease in price, reflecting a small rebound effect. Under the achievable and technical scenarios, Georgia households are forecast to consume an additional 260 billion Btu and 730 billion Btu of electricity by 2030 than in the baseline scenario. Nevertheless, Georgia households will still see energy bills rise at a slower rate under both scenarios saving Georgia residents approximately $87 million and $330 million respectfully over the decade.

The commercial sector sees the greatest reduction in price levels of the three sectors. Under the baseline, commercial electricity prices are expected to increase from 9.67 ¢/kWh in 2017 to 10.03 ¢/kWh in 2030 (in $ 2017). Both the achievable and technical scenarios, see electricity rates grow at a slower pace, relative to the baseline trend, rising to 10.03 ¢/kWh and 9.91 ¢/kWh respectfully by 2030. Over the next decade, both scenarios see rates increasing, on average, 0.33% and 1.17% lower than the baseline.

The decrease in price is partially offset by a slight increase in overall consumption. Under the achievable and technical scenarios, Georgia's commercial sector is forecast to consume an additional 22.7 billion Btu and 335.5 billion Btu of electricity in 2030 than forecast under the baseline case. Nevertheless, Georgia businesses will still see energy bills rise at a slower rate under both scenarios saving Georgia businesses approximately $155 million and $585 million respectfully over the decade.

In the baseline forecast, industrial electricity prices are expected to fall from 7.23 ¢/kWh in 2017 to 6.87 ¢/kWh in 2030 (in $2017). In both the achievable and technical scenarios, electricity rates decrease at a faster rate compared to the baseline – falling to 6.86 ¢/kWh and 6.79 ¢/kWh respectfully by 2030. Between 2020 and 2030, both achievable and technical scenarios see rates decreasing, on average, by 0.09% and 0.39% less than the baseline. Again, the greater the peak demand shaved, the greater the rate decrease. Natural gas rates remain largely unchanged between the baseline and the achievable and technical scenarios.

An increase in overall consumption partially offsets the decrease in price. Most notable, under the achievable and technical scenarios, Georgia's industrial sector is forecast to consume an additional 18.9 billion Btu and 205.9 billion Btu of electricity in 2030 compared to the baseline forecast. Nevertheless, Georgia manufacturers will still see energy bills rise at a slower pace under both scenarios, saving Georgia's industrial sector approximately $2.1 million and $12 million, respectfully, over the decade.

4.4. The impact of DR on pollution and public health

Fig. 7 shows the three trajectories of CO_2 emissions from 2020 to 2030, suggesting that the two DR scenarios would lead to lower carbon emissions, particularly after 2023. During the first several years, carbon emissions are higher in the DR case. With a potential 20% peak load shift, Georgia is estimated to avoid 0.16 $MtCO_2$ in 2030. With the addition of more affordable energy storage, Georgia can avoid 1.6 $MtCO_2$ in 2030, relative to the baseline forecast.

In the GT-NEMS baseline forecast, yearly electricity emissions are expected to rise by 6.4 $MtCO_2$ to 54 $MtCO_2$ by 2030 due principally to increased demand for electricity. In the achievable potential scenario, emissions would still rise but by only 4.4 $MtCO_2$. Over the decade, this would equate to 19.1 Mt CO_2 in avoided emissions. In the technical potential scenario, emissions would also still rise; in 2030, they would be greater than in the achievable scenario, but still less than in the baseline forecast. The lack of smooth and consistent trends is due to the year-over-year variabilities of generation unit dispatching. Over the decade, the technical potential scenario equates to 31.3 $MtCO_2$ in avoided emissions. The principal contributors to these reductions are cutbacks in electricity generation from coal and higher utility solar generation.

The expansion of demand response would deliver significant improvements to public health and ecological systems. For CO_2, the values are $54.37/metric ton avoided in 2025, and $59.1/metric ton avoided in 2030 based on findings of the Interagency Working Group (2016, Table A.3). Additional metrics and sources are listed in the notes to Table 2.

From an environmental and public health standpoint, the adoption of demand response solutions can lead to air quality improvements over existing alternatives. For example, simple cycle gas turbines or coal power plants that run during peak hours tend to be inefficient and higher-emitting. Offsetting these peaking plants with demand response can significantly reduce environmentally harmful emissions (Dahlke, 2014; Smith and Brown, 2015). Consistent with the change in the generation mix shown in Fig. 3, the result is significant reductions in many pollutants, and four of these are examined here: SO_2, NOx, PM 2.5 and PM 10 (Fig. 8). The air quality impacts of DR will necessarily be

Table 2
Monetized Environmental and Public Health Benefits of Potential Pollution Reduction from Demand Response, in $2017[a].

		Difference From Baseline (Short Tons, Megatons for CO_2)			Monetized Benefits (in million 2017$)		
		2025	2030	Cumulative	2025	2030	Cumulative
CO_2	Achievable Potential	2.25	1.73	16.91	122.33	102.24	913
	Technical Potential	5.66	1.45	27.74	307.72	85.70	1,470
SO_2	Achievable Potential	949	871	7,033	16.66	15.30	123.48
	Technical Potential	2,066	493	9,788	36.27	8.66	171.86
NOx	Achievable Potential	1,383	1,288	10,718	4.68	4.36	36.29
	Technical Potential	3,043	780	14,518	10.30	2.64	49.16
PM 2.5	Achievable Potential	69.88	60.83	554.44	1.15	1.00	9.09
	Technical Potential	278.49	41.76	1,560	4.57	0.68	25.58
PM 10	Achievable Potential	125.09	112.06	980.46	0.02	0.02	0.18
	Technical Potential	450.24	68.63	2501.31	0.08	0.01	0.46
Total	Achievable Potential				144.84	122.92	1,083
	Technical Potential				358.94	97.69	1,718

[a] The following values were used to convert tons of avoided pollution to social benefits in $2017: SO_2 ($17,558/short ton) and NOx ($3,386/short ton) (Muller, 2013). For CO_2, the values are $54.37/metric ton in 2025, and $59.1/metric ton in 2030 (Interagency Working Group, 2016; Table A.3). Social benefit values for particulate matter are: PM 2.5 ($16,477.01/short ton) and PM 10 ($186.47/short ton), in $2017, (Muller, 2013) using inflation rates from the Bureau of Labor Statistics calculator.

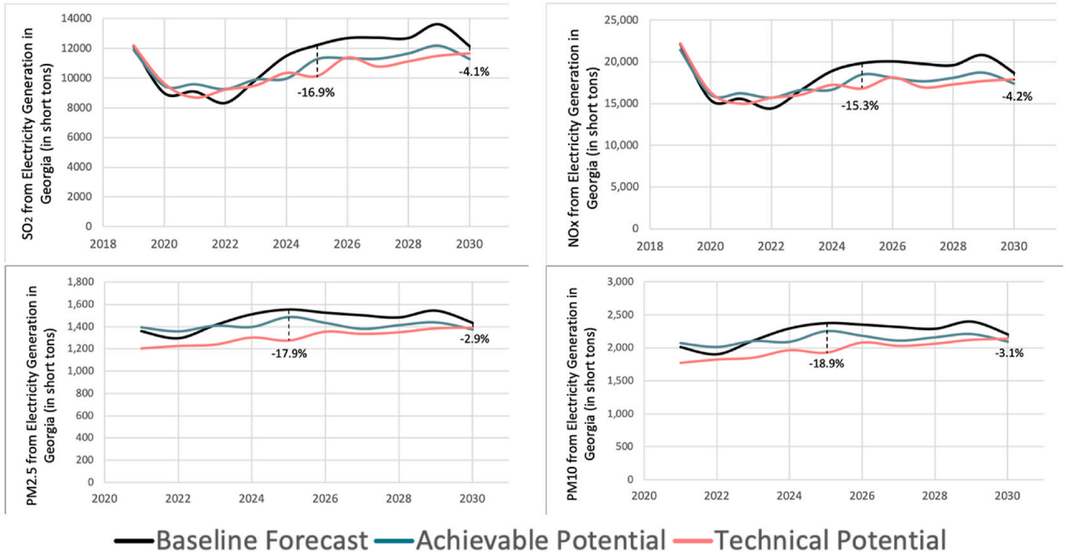

Fig. 8. Reduction in Criteria Pollutants from Increased Demand Response for SO_2, NOx, PM2.5 and PM10 (in million short tons).

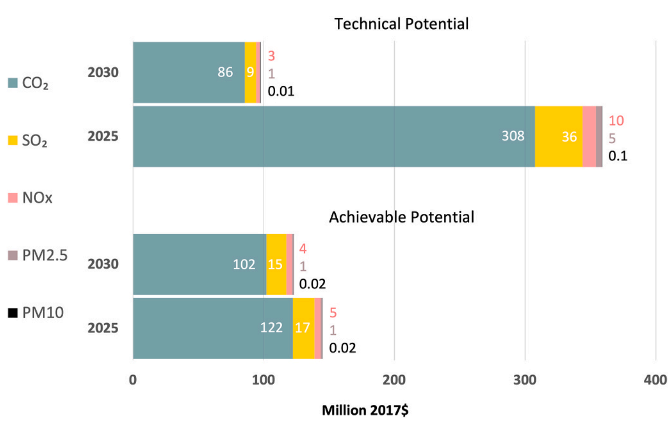

Fig. 9. Monetized environmental and public health benefits of potential pollution reduction from demand response.

case-specific, depending on the DR program's nature, the mix of generation serving a locality, and consumer characteristics.

Public health and environmental damages from the emissions of CO_2 from fossil fuels are represented in the social cost of carbon and were estimated by the Interagency Working Group on Social Cost of Greenhouse Gases, United States Government in 2018, to be worth \$59.1 per metric ton of displaced carbon (in \$2017, using a 3% discount rate). Damages include, but are not limited to, "changes in net agricultural productivity, human health, property damages from increased flood risk, and the value of ecosystem services due to climate change." (Interagency Working Group, 2016, p. 3).

The expansion of demand response reduces air pollution: as peak loads are cut, both coal plants and single-cycle natural gas plants are used less. The difference between the baseline and the two scenarios reaches its greatest extent in 2025 with the technical potential exhibiting between 10.2% and 17.1% lower levels of emissions amongst the three pollutants. Under both achievable and technical scenarios, SO_2 sees the largest cumulative cutback of emissions at 5.9% and 8.6% respectfully. NOx, PM 2.5 and PM 10 also see significant marginal cutbacks (Table 2, Fig. 9).

The social and economic benefits of demand response include affordability and potentially greater accessibility by low-income households (versus, for example, rooftop solar). Besides moderate upfront costs, some studies found that residential demand response technologies generate overall energy savings in addition to shifting demand to low-rate off-peak hours. TVA mentions DSM/DER initiatives concerning stewardship, energy equity, and environmental justice. On the other hand, Xu (2019) argues that DR savings benefits may be limited for low-income households (or even create disadvantages) due to residential status (as renters versus owners), less flexible daily routines and schedules, and an absence of targeted DR appliances such as clothes washers, dryers, and dishwashers.

Together with microgrids, grid flexibility solutions, and distributed energy resources, DR can improve resiliency and flexibility to mitigate increasingly volatile impacts on the grid, such as heat waves and cold snaps (Peláez and Nunno, 2017). For example, microgrids played a crucial role in making communities more resilient in the midst of Superstorm Sandy (Revkin, 2012). DR can contribute to system flexibility, which is likely to be a growing need with expanding renewable electricity and climate extremes.

DR solutions requiring high adoption rates of lithium-ion batteries may impose environmental risks regarding their end-of-life disposability (USEPA, 2013). When paired with rooftop solar systems, end-of-life panel disposition must be addressed to prevent environmental contamination from toxic materials contained within the PV cells, such as cadmium, arsenic, and silica dust. The national Solar Energy Industries Association (SEIA), whose members operate take-back and recycling programs, assists with end-of-life recycling and management through its national PV recycling program. Large-scale adoption will likely necessitate additional recycling measures.

5. Discussion

Section 4 documents the DR gap between the baseline forecast and the achievable and technical scenarios, which substantiates the conclusion that there is an economically inexplicable lack of investment in demand response policies and measures in Georgia.

While there are many barriers to expanding the use of DR, promising policy tools, new technologies, and novel business models also exist (Fig. 10). These are aggregated below into financing innovations, business and policy innovations, and infrastructure modernization.

Enrolling customers in DR pricing schemes remains a challenge (Faruqui and Hledik, 2018). Consumer participation among active or pilot pricing schemes is often 10% or less of the target population (Parrish et al., 2019). The opacity of existing dynamic pricing or other direct load control schedules can create mistrust, which increases the

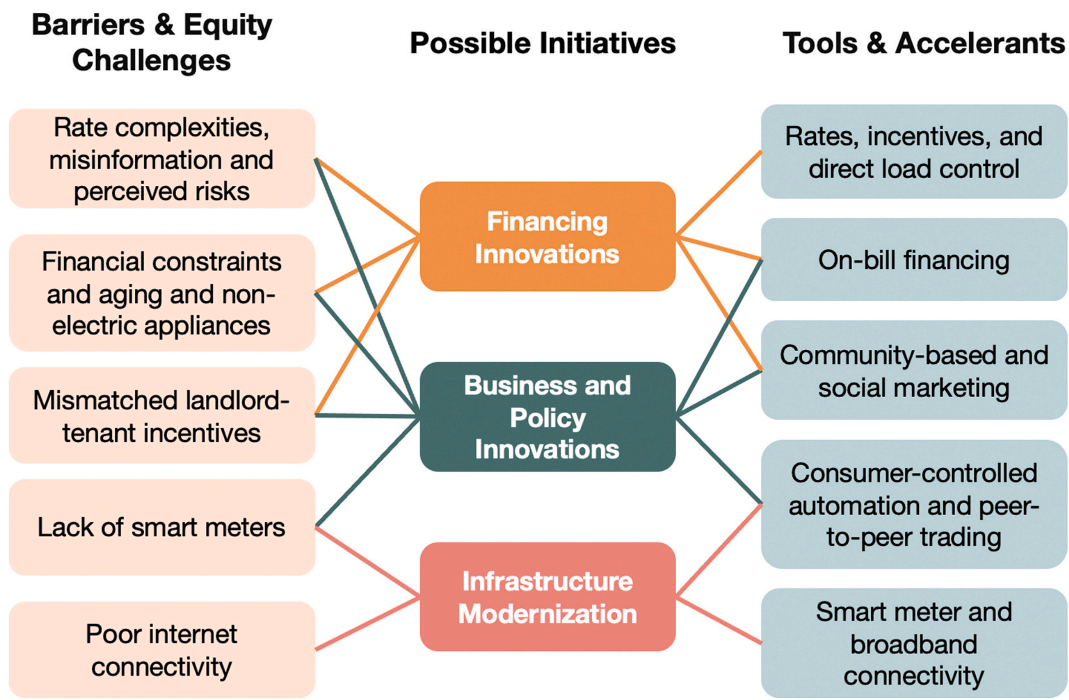

Fig. 10. Barriers and accelerants analysis for demand response.

perception of risk for consumers (Parrish et al., 2020). Finally, there is limited consumer awareness and knowledge about smart thermostats and energy management systems, and how data from them is used, adding to consumer mistrust of IOT technology (Brown et al., 2018). The actual electricity price in a customer's bill is often not apparent, as final bills include other charges such as taxes, service fees, and environmental compliance costs, and they may not include a breakdown between electricity prices and other charges (O'Connell, et., 2014). Also, providing a range of transparent and well-communicated rate options for consumers to choose from has the potential to expand participation significantly among target populations. Perceptions of risks and needs can differ between households and sectors, and through providing choice, consumers can better tailor demand response to their individual needs.

DR programs can also be handicapped by their inability to address rental properties and aging appliances and HVAC systems that are challenging for load control programs. More than half of low-income households in the U.S. and 37% of all households in Georgia live in rental units (Hernández et al., 2016). Innovative processes are needed to mitigate related problems of mismatched incentives between landlords and tenants, including community-based support and social marketing that have proven to be successful in affordable housing energy-efficiency programs (Keilty, 2018; Brown et al., 2021). In several case studies, Christensen et al. (2020) shows the value of coupling incentives with pricing schemes. Similarly, adding on-bill financing approaches to demand-response programs could help utilities achieve a more favorable return on their investments. This was illustrated in an analysis of a proposed program that would deploy PAYS® to offset utility investments in three smart energy-efficient appliances: dishwashers, refrigerators, and clothes dryers (Qaseem et al., 2020).

Advocates are beginning to re-conceptualized DR as a "flexible response" alluding to its ability to help balance renewable generation (Smith and Brown, 2015; Polymeneas et al., 2021). Decarbonizing the grid with the introduction of more renewables will require the addition of more flexible resources and more dynamic energy products. Utility business models will need to offer a platform of products and services that enable more dynamic energy offerings such as those provided by DR capabilities (either through the utility or by enabling other market players to emerge who can offer DR solutions). For example, a third-party provider could facilitate aggregation and peer-to-peer trading of surplus generation from rooftop PV (Valentine et al., 2019).

Similarly, there is a range of innovative products, flexible and cost-reflective rate-design options that can be deployed to encourage greater customer participation. The Business Requirements Specifications developed by California Independent System Operator (ISO) provide examples of an effective system enabling solutions such as DR bidding and adding a load-shifting product behind the meter (BTM) storage devices (California ISO, 2020). Additionally, the California Energy Commission's report, which focuses on non-residential lighting systems with DR capability, outlines a market transformation approach to accelerate DR adoption (Schwartz et al., 2019).

Social and economic benefits can be maximized by introducing frameworks to evaluate how best to optimize societal and rate impacts and tradeoffs. For example, the framework developed by the National Action Plan on Demand Response Cost-effectiveness Analysis Working Group can be applied to consider costs and benefits on a case-by-case basis (Taylor et al., 2015).

In order to mitigate potential DR disadvantages and/or to enhance benefits for low-income households, recommendations include expanding access to programmable thermostats, removing cost barriers to smart grid technologies, offering programs that are more tailored to low-income household activity and appliance status or schedules, increasing access to community-based approaches among multi-family units, and promoting incentive-based DR programs that minimize "penalties" for not being able to reduce or shift inflexible load with higher pricing during peak hours (Xu, 2019).

Finally, infrastructure gaps need to be filled to equip potential DR participants with smart meters and broadband access. Without such infrastructure, real-time rate structures are unavailable to customers. This could be done by expensing these infrastructure costs in the rate base of electric utilities, which would enable citizens to be DR- and solar-ready and better equipped to prosper in the current information age. Business models for utilities need to be reconceived, to consider the rate-basing of such investments that are in society's best interest. However, public utility regulators in some states have denied requests by investor-owned utilities to recover the cost of smart meters and other infrastructures, which underscores the key role of public policies as enablers or barriers to DR (Kentucky Public Service Commission, 2018; Massachusetts Department of Public Utilities, 2018).

6. Conclusions and policy implications

As Georgia's renewable energy resources increase, the flexibility of active energy consumers can provide increasing value. Buildings can become energy hubs, supporting smart energy grids with demand response strategies. Digitally connected smart thermostats and energy management systems can enable consumers to visualize, monitor, and manage electricity consumption within their household and office complexes. Also, by expanding the DR portfolio, more variable renewable electricity could be deployed.

Our analysis documents how demand-side solutions can reduce energy bills while simultaneously resulting in cleaner air and improving the public's health. We show how DR clips customers' demand for electricity during peak hours when electricity prices are high, and when polluting peaker plants might otherwise be deployed.

Managing the demand for electricity has historically been a challenging strategy, and this is underscored by our estimation of the size of the DR gap in Georgia. Financing, business and policy innovations as well as infrastructure modernization could enable the expansion of demand response. To ensure that goals of equity and socio-economic inclusion are met, DR programs need to be designed to engage rental properties and address the replacement of aging and non-electric appliances and HVAC systems that are challenging for load-control programs.

CRediT authorship contribution statement

Marilyn A. Brown: designed the research. collected data, performed research, and wrote the paper. supervised the study, Data curation, Writing – original draft, Supervision. **Oliver Chapman:** collected data, performed research, and wrote the paper, Data curation, Writing – original draft.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.enpol.2021.112533.

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