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# Dynamic Response of Monoethanolamine (MEA) CO2 Capture Units

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## Abstract

Coal-fired power plants need to respond to changes in electricity demand on diurnal, weekly, seasonal, and yearly time scales. The scale and frequency of these responses are forecasted to increase as levels of variable renewable energy sources become a larger part of the electricity supply. To respond to climate change concerns, it is also anticipated that the coal-fired power plants of the future will incorporate carbon capture and sequestration (CCS) technologies. Therefore, it is important to understand the dynamic response of coal-plants with CCS.

A variety of engineering studies have been published that investigate the energy penalty and design requirements for coal-fired plant running at static power output and carbon capture rate of 90 percent; however, few of these studies explore the ability of the capture unit to respond to changes in load and capture rates. Noting that amine absorption is considered the most advanced near-term technological solution for carbon capture, this paper provides an analysis of the dynamics of a MEA capture unit. This analysis enables the evaluation of the ability of coal-fired CCS power plants to provide load following support at different ramp rates and at varying levels of capture.

A dynamic kinetic model of an MEA capture plant was developed using Aspen Dynamics®. The model is used to determine the dynamic characteristics of the capture plant for load following by simulating various ramp rates of flue gas flow from the power plant to the capture unit. These results are used to determine the ability of the capture plant to control power output to the grid and the impact on performance parameters such as the capture rate and energy consumption. The results shown that the capture plant operates on similar time scales of a coal-fired power plant. The capture plant will not prohibit the ability of the coal plant to adjust output.

## Introduction

Electricity generation from fossil-fuel power plants is one of the largest sources of carbon dioxide emisisons (IPCC 2005). To reduce the amount of emissions from these power plants, carbon capture and sequestration is seen as one of the most promising technology options. In particular, chemical absorption is the most widely studied and advanced subset of these technologies. To date, most studies have looked at the steady state, full load, 90% capture operation of the CCS unit (Freguia et al. 2003; Abu-Zahra et al. 2006; Zhang et al. 2009).

Current coal-fired power plants need to be able to ramp to respond to changes in electricity demand and prices. If CCS is integrated into the power plant, it is important to determine the ability to respond to the changes in the power plant that may potentially affect the capture operation. Studies investigating load balancing with increasing penetration of renewables show that traditional baseload generation will need to be able to respond to a wide range of operating conditions and ramp rates (IEA 2011; GE Energy 2010). In addition, the operation of a flexible carbon capture system may enhance plant operating economics in by reducing steam required for solvent regeneration (Cohen 2011). Understanding the dynamics of the capture system is important for the operation of the power plant.

Other papers have considered the part-load, steady state operation of the capture unit integrated with the power plant (Chalmers et al. 2007; Haines et al. 2009), but did not consider the dynamic changes of the capture unit while transitioning to part-load operation. While many studies have investigated individual process units, few have studied the dynamics of an integrated carbon capture system. Lawal et al. (2009) and Kvamsdal et al. (2009) focused on the dynamic modeling of the absorber unit and Ziaii et al. (2009) focused on optimizing the energy usage of a standalone stripper model.

This paper considers the dynamic operation of an absorber/stripper post-combustion monoethanolamine (MEA) capture plant of a nominal 500 $MW_{th}$ coal-fired power plant and investigates the time scales and effects of how the capture plant responds to step changes in the various inputs for an integrated absorber/stripper capture model. The cycling of a coal-plant is reflected in the changes in the flue gas flow to the capture plant, changes in the capture rate for environmental or economic reasons, and changes in the amount of available steam to the reboiler. This will help determine the deviations from set points and the ability to return to steady state. This study will look at the range of operational issues presented as the capture plant undergoes the changes that are typical to the operation of a coal-fired power plant.

## Description and Application of Equipment and Processes

### Process Description

A steady-state model of an absorber/stripper post-combustion MEA capture unit was created in Aspen Plus Version 7.3 based on the work of Kothandaraman (2010). The steady-state model was used for model development and verification. The absorber and stripper were assumed to have 30 equilibrium stages and 20 equilibrium stages, respectively. The sizing of the columns was done to accommodate the flow from a nominal 500 $MW_{th}$ coal-fired power plant using only one absorber/stripper train. The major process components that were modeled are shown in Figure 1.

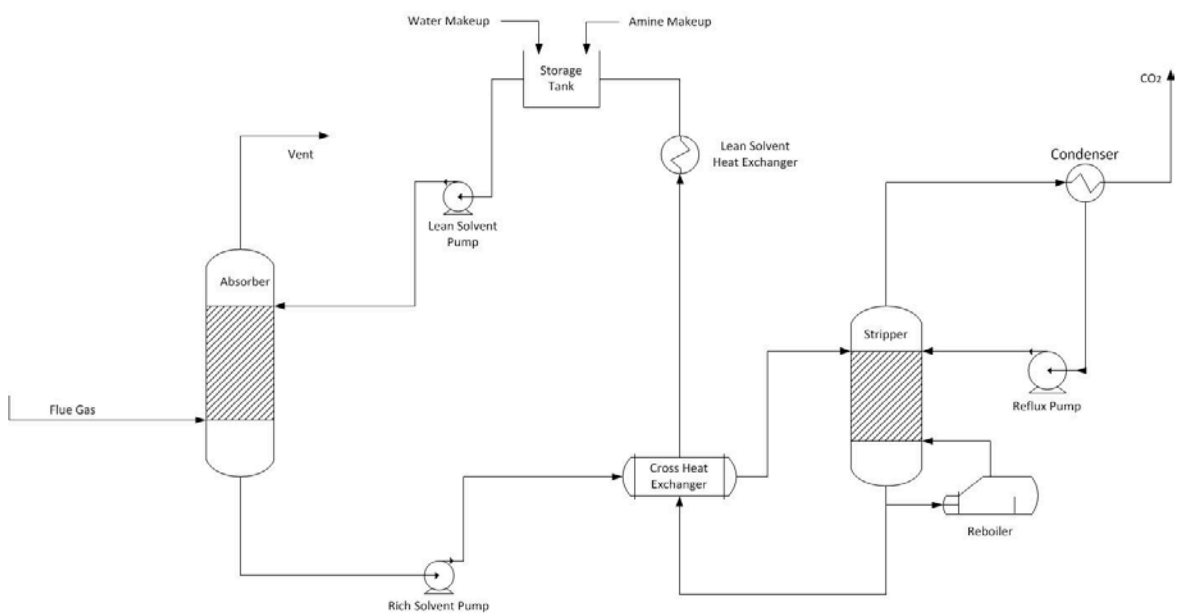


Figure 1. Process flowsheet for absorber/stripper post-combustion capture process

For this study, the electrolyte non-random two-liquid (ELECNRTL) property method was used. The absorber/stripper chemistry was represented with seven reactions. $SO_2$ and $NO_x$ were assumed to be inert gases for the purposes of the model.

$$H_2O + MEA^+ \leftrightarrow MEA + H_3O^+ \quad (1)$$
$$2\ H_2O \leftrightarrow H_3O^+ + OH^- \quad (2)$$
$$HCO_3^- + H2O \leftrightarrow CO_3^{--} + H_3O^+ \quad (3)$$
$$CO_2 + OH^- \leftrightarrow HCO_3^- \quad (4)$$
$$HCO_3^- \rightarrow CO_2 + OH^- \quad (5)$$
$$MEA + CO_2 + H_2O \rightarrow MEACOO^- + H_3O^+ \quad (6)$$
$$MEACOO^- + H_3O^+ \rightarrow MEA + CO_2 + H_2O \quad (7)$$

The dimensions of the absorber are 17 m in height and 12 m in diameter and the dimensions of the stripper are 15 m in height and 7 meters in diameter. The absorber and stripper pressure were set to 1 atm and 1.75 atm, respectively. The condenser was modeled externally from the RadFrac column due to convergence issues, but his did not affect the results of the model. To achieve water and amine balance for the model due to process losses, the makeup was added in the surge tank. The water makeup was used to maintain to 30-wt% of the MEA solution, while the amine makeup was added primarily for model convergence. Temperature was maintained through the system of heat exchangers shown above. The lean solvent heat exchanger and the condenser were modeled to maintain a constant exit temperature, while the cross heat exchanger was modeled to allow for changes in process conditions allowing the exit temperatures to be free variables in the model.

**Dynamic Simulation and Control Strategy**

The steady-state model was exported to Aspen Dynamics and the flow-driven type model was chosen. Figure 2 illustrates the control structure of the post-combustion MEA capture. The primary objective of the system is to maintain a specified capture rate of 90%. To achieve this level of capture, the lean solvent circulation rate is manipulated. The capture rate is determined by measuring the incoming mass flow of $CO_2$ to the absorber and the mass flow exiting the absorber through the vent stream. To control the lean solvent rate, the flow from the storage tank is manipulated.

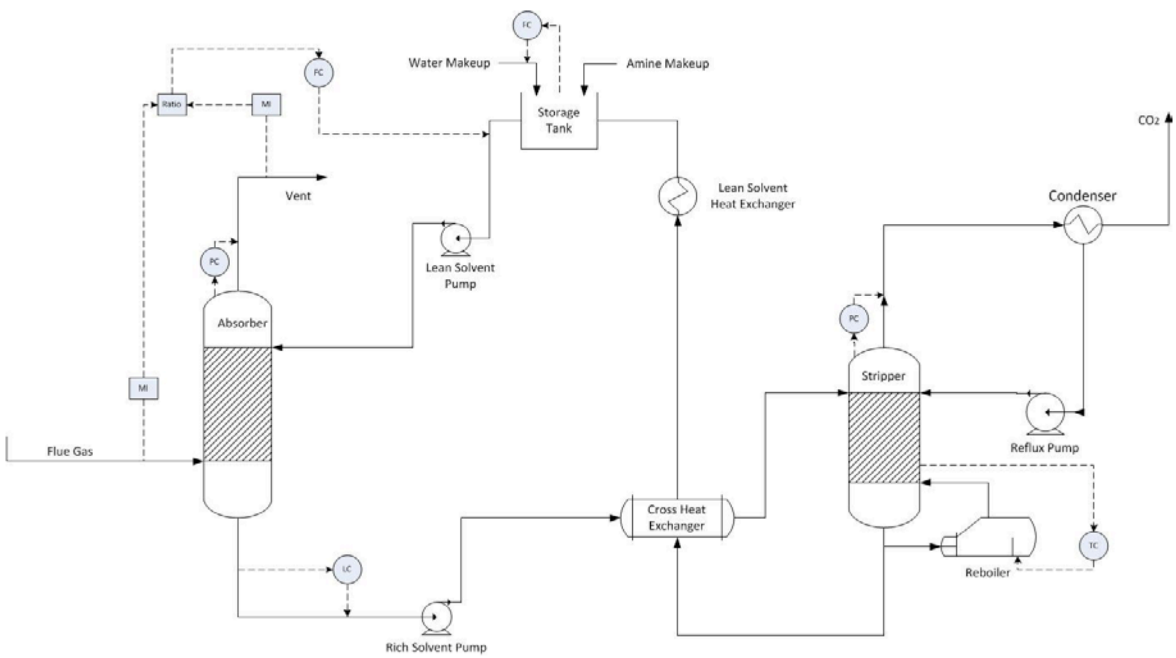


Figure 2. Absorber/stripper process flow diagram with control structure

The lean solvent loading is one of the key parameters in $CO_2$ capture. To regenerate the rich solvent from the absorber, heat is applied in the form of steam to the reboiler to drive off the $CO_2$ from solution, resulting in an energy intensive process. The amount of reboiler duty drives the equilibrium of the lean solvent at the fixed pressure of the column. From the steady-state simulations, it was determined that the energetic optimum for the lean concentration is 0.20 on a dry molar basis. The study by Panahi et al. (2011) stated that a proper indicator for lean loading is the column stage temperature. A direct measurement of the lean loading would be costly and time intensive. The reboiler temperature was maintained at a temperature of 124°C to achieve the desired lean loading.

For the purposes of the model, the steam temperature and pressure were assumed to be constant throughout the operating range. This paper does not consider the issue of steam extraction from the crossover piping of the steam turbine. Given the arrangement of the turbine system, the steam may deviate from full load temperature and pressure at different operating conditions.

The other process controls were used to control the operating pressure and sump level of the absorber and stripper. To maintain the operating level of the columns, the gas flow exiting the column was manipulated. To maintain the sump level of the columns, the liquid flow was manipulated. The heat exchangers were modeled as instantaneous processes.

## Presentation of Data and Results

Three disturbances were tested using the dynamic simulation. These disturbances were used to determine the dynamic behavior of the process variables, the response time of the system and time to achieve steady state, and the performance of the system in the new steady state. The three disturbances were to the flue gas flow rate to simulate a change in plant load, a change in capture rate to simulate flexible operation for economic reasons, and a change in the reboiler temperature to decrease steam extraction from the turbine and increase power output.

**Disturbance to flue gas flow**

To analyze the dynamics of the system for a change in fuel consumption by the base coal plant, a negative 10% step change was made to the incoming flue gas flow, steady state was achieved again, and a positive 10% step change was made to return to the original inputs to the capture plant. The system was run for 2 hours before the step change was induced to ensure it had reached steady state. The negative step change was done at simulation time of 2 hours and the positive step change at 5 hours as shown in Figure 3.

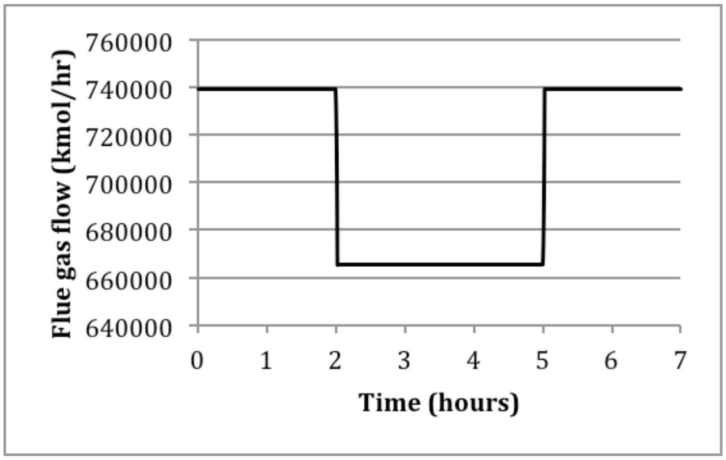


Figure 3. Flue gas flow rate distrubance

For both step changes, the capture rate deviated from the set point value of 90% by 3.3 absolute percent for the negative step change and 3.1 absolute percent for the positive step change as shown in Figure 4. The dynamic results are shown in Figure 4. Figure 4 shows that steady state was achieved with regard to the 90% capture set point at approximately 10 minutes from the time of disturbance. The lean solvent flow rate deceases by 13% for the negative 10% step change in the flue gas flow rate as demonstrated in Figure 5.

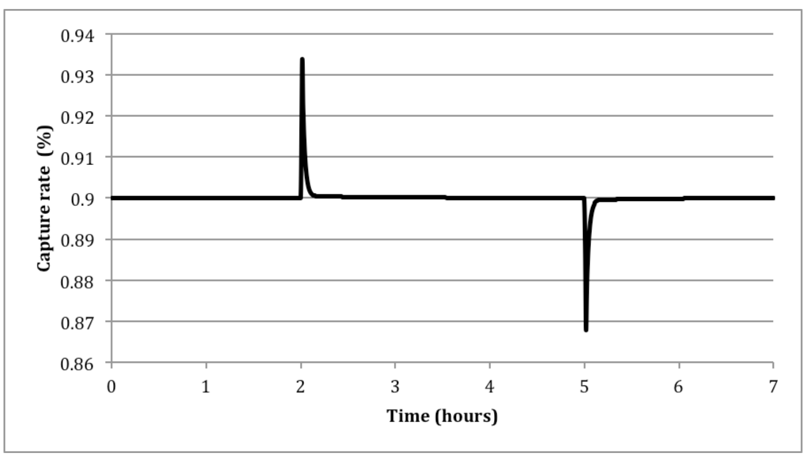


Figure 4. Capture rate dynamics for flue gas flow disturbances

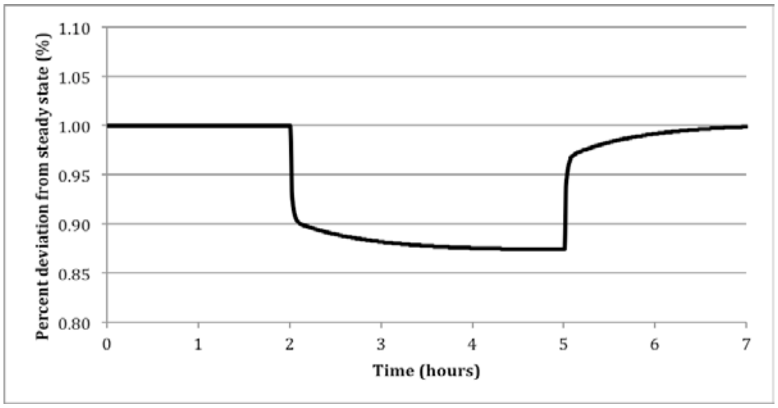

Figure 5. Change in lean solvent flow for flue gas disturbances.

The reboiler temperature control dynamics for the -/+ 10% step change in the flue gas composition demonstrated similar time scales to achieve the steady state. There was a 3-minute lag in the system before the disturbance in the flue gas flow reaches the measurement system of the reboiler. While this result will be unique to this particular system, this result will help in designing optimal control structures to achieve steady state levels at faster rates. The reboiler temperature does not deviate from the temperature set point of 124°C by more than 0.2°C.

**Disturbance in capture level**

The dynamics of the system to response to changes in deviations from the desired capture level were simulated by creating a negative 30% (absolute) step change to the capture level followed by a positive 30% (absolute) step change as shown Figure 6. This was to investigate the ability of the capture plant to increase the power output sent to the grid during times of peak demand. By lowering the capture rate, the capture unit vents more $CO_2$ by reducing lean solvent flow, which causes a subsequent reduction in steam required to maintain lead loading. This reduction in steam enables more to be sent to the low pressure turbine, increasing power generation.

The system was run until steady state was achieved and at simulation time 2 hours the negative step change was induced.

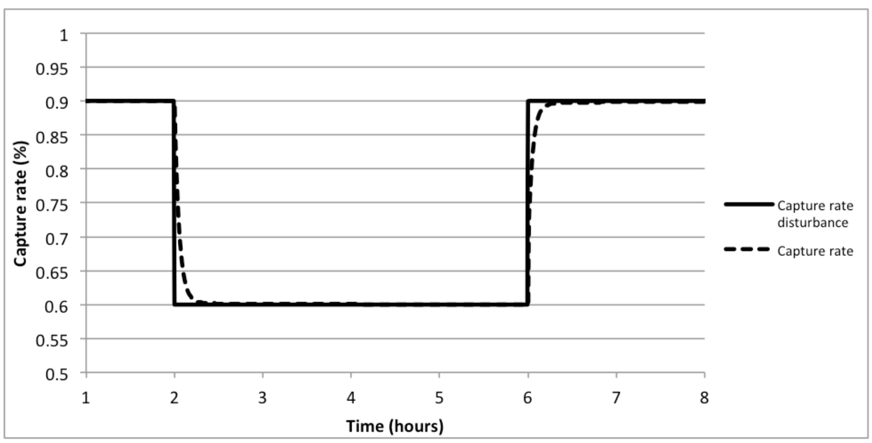

Figure 6. -/+ 30% (absolute) step change to capture rate

As can be seen in Figure 6, the step change in capture rate provides a similar response as a change in flue gas flow. Steady state is achieved within 24 minutes for this positive and negative step change. The reboiler temperature controls respond similarily as to the disturbance in flue gas flow. The steady state temperature did not devaiate more than 0.4°C from the 124°C set point. Steam demand to the reboiler was reduced by 35% and achieved steady state within approximately 120 minutes. These results demonstrate that the capture unit can flexibly operate at off-design $CO_2$ capture levels.

**Disturbance in reboiler duty**

Another operational strategy that could be used to increase power production during times of peak demand is to directly reduce the steam demand in the reboiler, which enables more steam to remain in the turbines for power production. This will increase the lean solvent loading and decrease the capture rate. For this simulation, the set point of the reboiler temperature was reduced from 124°C to 118°C and the lean solvent flow controller was turned off to maintain constant solvent flow to the absorber at simulation time 2 hours. The reboiler temperature set point was set back to 124°C at 5 hours. The reboiler temperature manipulation acts as an indirect manipulation on the steam demand given the control structure of the capture system. By reducing the temperature while maintaining constant solvent circulation throughout the system, the steam demand will decrease as shown in Figure 7.

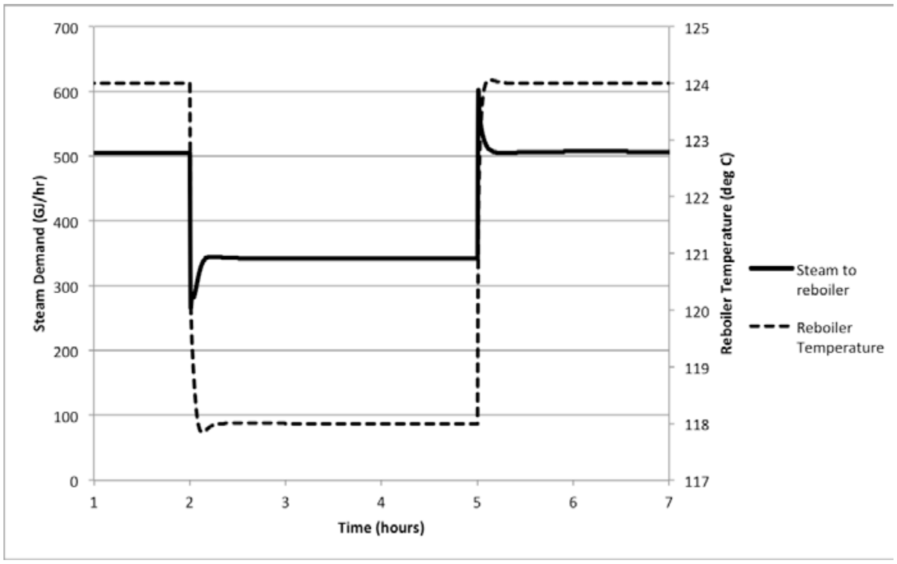


Figure 7. Reboiler response to -/+5% step change in reboiler temperature

The decrease in the set point temperature of the reboiler to 118°C decreases the steam demand by 32%. Steady state with regard to the reboiler temperature was achieved in 20 minutes. The decrease in the temperature of the reboiler increased the lean loading by 50% from 0.20 mol/dry mol to 0.30 mol/dry mol. This increase in lean loading, while maintaining constant solvent circulation, is reflected in the capture rate, shown in Figure 8.

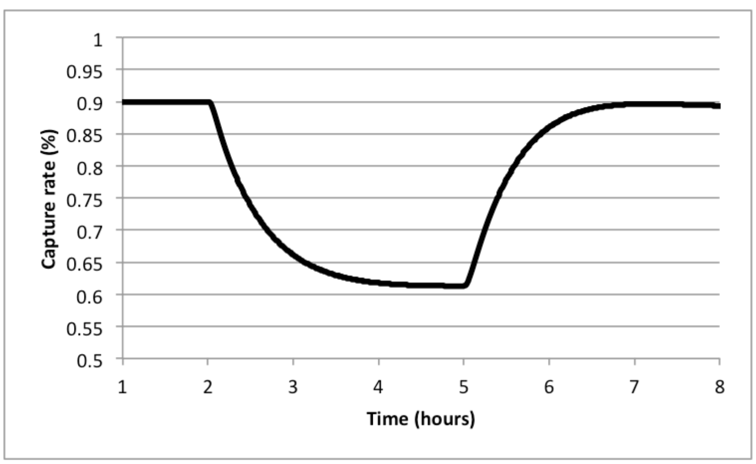


Figure 8. Capture rate response to -/+5% step change in reboiler temperature

The capture rate decreased from 90% from the initial steady state to 61% after the reboiler temperature disturbance was initiated. Capture rate steady state was achieved within 120 minutes for the reboiler temperature disturbance.

## Discussion

The simulations conducted for this study assumed that the capture system operated in isolation from the power plant. Changes to capture system operation were assumed to not affect the operation of the coal plant as the disturbances were taken only as inputs to the capture system. The turbine configuration and steam extraction connection could limit the availability of steam for the reboiler and thus affect the control structure and operation of the capture system. The power plant and capture system control structures will need to be integrated to reflect these limitations.

This study only considered reasonable ramp rates and changes in operating conditions of a coal-fired power plant. Fuel burn rate in a coal-fired power plant can change at the upper limit of approximately 4% per minute. Combined cycle gas turbines (CCGT) have the ability to ramp up and down at faster rates and further study is necessary to determine the response of the capture system to load changes of greater rates and magnitudes. The start-up and shutdown of the capture system was not considered but would have to be studied to determine the effects of the power plant to come online.

## Conclusions

Three operation scenarios were simulated to determine the dynamic operation of the post-combustion capture system: flue gas flow disturbances, capture rate disturbances, and reboiler temperature distrubances. The simulations showed that the capture system can respond dynamically at time scales similar to the operation of a coal fired power plant. The capture system can operate effectively in load following mode when the flue gas flow is changed. The capture system can also operate at off-design capabilities to enable a lower steam requirement for the reboiler. This will allow the power plant generate more power during times of peak demand.

## Acknowledgments

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