# Analysis of Methane Mitigation Options using the US-EPA MARKAL Model

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## Introduction

The US Environmental Protection Agency (EPA) has augmented the EPA US-national MARKAL[1] model to include the ability to track methane emissions and assess mitigation strategies that interact with the energy system[2]. This methane accounting sub-model[3] includes emission sources and mitigation technologies in the following five methane subsystems: Municipal waste and landfills; Natural gas production, transmission/storage, and distribution; Coal production; Oil production, and Manure management.

The methane sub-model in the EPA US-national MARKAL model has been developed and calibrated to perform the following functions:

1. Provide projections of future methane emissions from the energy system;
2. Assess potential mitigation levels of methane emissions by energy system component;
3. Evaluate the benefit and costs of policies, programs, and actions to reduce methane emissions;
4. Help to prioritize emission reduction opportunities in terms of cost-effectiveness and ancillary benefits, and
5. Produce emission abatement cost curves.

This paper describes analyses that were performed to investigate the effectiveness of various technologies and policies for reducing methane emissions.

## Methane Subsystem Description

Data on historical and projected future methane emissions was developed from various EPA documents[4], the AEO 2002[5], and a few other sources[6]. The full approach employed for modeling each of the five methane sectors is described in another paper[7]. This paper will summarize the model only.

In each sector, the model simulates activities that produce methane, derives emission estimates from these activities, provides alternatives for handling the produced methane, and implements methane mitigation technologies as appropriate, based on least-cost and in response to policy constraints applied by the user. The nature of the methane subsystems is represented by the Municipal Solid Waste (MSW) and Landfills diagram Figure 1.

### *Municipal Solid Waste (MSW) and Landfills*

Methane is generated through a biological process, which breaks down the organic materials, ferments the materials and then methane-producing bacteria converts these materials to biogas (50% methane) through an anaerobic process. The resulting emissions from landfills are divided into two categories. First are methane emissions from the pre-2005 landfills, which are based on the known amount of waste in place that is still active. The model includes a variety of mitigation technologies that can capture landfill gas to reduce emissions from these landfills. After 2005, the model tracks MSW utilization, and mitigation options are expanded to include landfills and diversion of MSW to other types of use such as composting, mechanical biological treatment, etc.

Landfills are modeled as large, medium and small to account for different methane generation rates and the applicability of the Landfill Rule[8] to large and medium landfills. Because MSW deposited in landfills will generate methane over a 30-year period the post-2005 landfills are modeled to accept a one-time input of MSW which continues to generate methane for their full lifetime (30-years). Characteristics for the MSW and landfill gas mitigation technologies were developed from EPA and other sources[9].

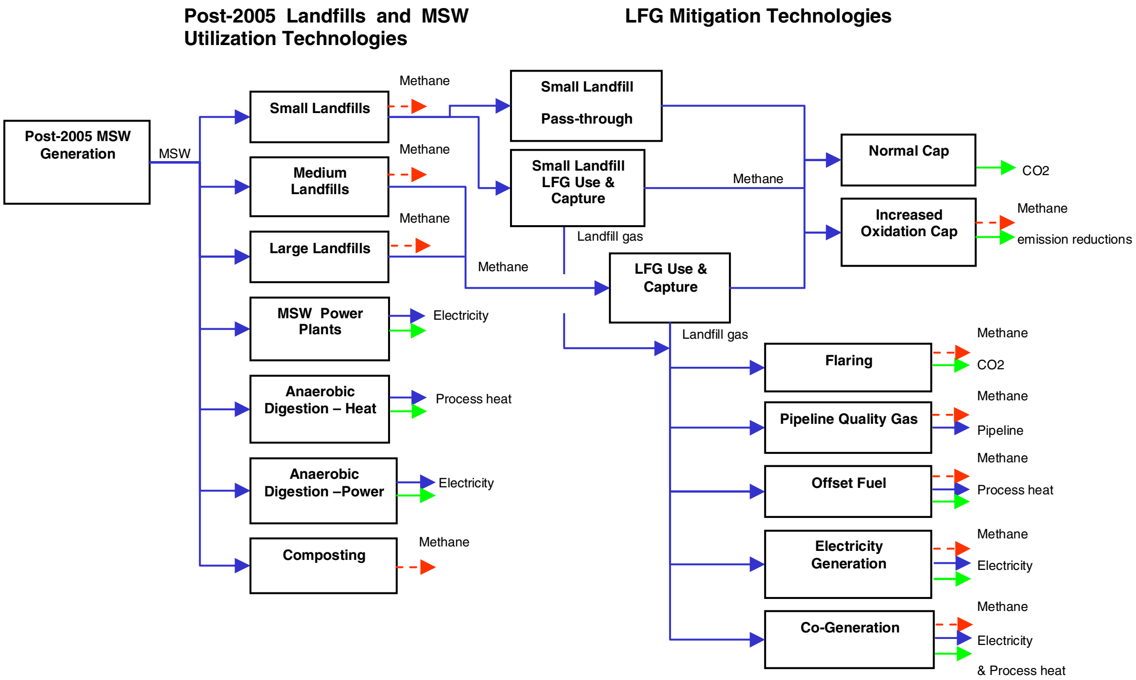


**Figure 1: Methane Subsystem for New Municipal Solid Waste**

## *Coal Mining*

Methane emissions from coal mining result when methane is liberated from the coal and surrounding strata during mining. Emissions also occur during production and transport of coal. Methane emissions from production and transport of surface-mined coal are accounted for in the model, but have no mitigation options. Underground-mined coal has several mitigation options including degasification required prior to mining, ventilation air methane capture and use, and gob gas upgrading for pipeline injection. The coal is tracked by basin as the methane release rates vary by region.

## *Natural Gas Production, Transmission and Distribution*

Natural gas or methane emissions occur generally during the processing, with normal operations, routine maintenance, and during systems upsets. All three major stages of natural gas handling were modeled: domestic gas production, transport and storage of domestic and imported natural gas, and distribution to end-users. Each of the major stages (production, transmission and distribution) is modeled separately, though fully inter-connected. Within each stage, mitigation technologies specific to that stage are implemented in series allowing competing and complimentary options to be implemented.

Imported gas and other pipeline quality gas (e.g. from coal mining) are introduced into the natural gas sector after the production process. Methane that is captured in the natural gas system by mitigation technologies is added back to the flow in the next stage of the natural gas system.

### *Manure Treatment*

Methane emissions from livestock manure management are generated from the anaerobic decomposition of the manure and are dependent on three principal factors: the manure source, the manure management system and the emission mitigation technology. Because liquid management systems promote anaerobic processes that generate methane, while dry management systems maintain greater exposure of the manure to air and do not promote methane generation, the manure sources were grouped according to their likelihood of using liquid or slurry management systems.

Dairy cows and swine were modeled as the dominant manure sources that could use liquid manure management systems, and all other livestock were modeled as using dry treatment systems. The methane emissions from dry treatment have no mitigation options, while the liquid management systems have several mitigation technology options.

### *Oil Production*

Methane emissions generally occur during crude oil production as a fugitive or vented emission. Emissions and mitigation options from domestic oil production are modeled for the Lower 48 and Alaska separately to allow for different emission factors and mitigation costs for these two regions. Both domestic oil sources are further segregated into on-shore and off-shore production, so that different mitigation options can be applied appropriately.

Table 1 lists the numbers of emission and mitigation technologies that comprise the methane sub-model.

**Table 1: Summary of Technologies in the Methane Subsystem**

| Methane Sector | Emission technologies | Mitigation technologies |
|---|---|---|
| MSW / Landfills | 6 | 11 |
| Natural Gas | 3 | 26 |
| Coal | 40 | 24 |
| Oil | 4 | 8 |
| Manure | 4 | 5 |
| Total | 57 | 74 |

## Model Calibration

In the model calibration run, the methane mitigation options were deactivated to allow calibration to the methane emission in line with the EPA methane inventory for 1995 and 2000, and comparison of the model's projected emissions (to 2030) to the EPA baseline emission projections (to 2020 only). As can be seen in Figure 2, the methane emissions reported by the model from the coal, oil and manure sources closely match that of EPA, while the estimates diverge, some for landfills and natural gas. For landfills, the differences are due to an assumed linear decay rate for emissions from existing landfills in the model. Natural gas emissions in the model are slightly different from EPA projections because the demand for natural gas is slightly different in the EPA projections (based on AEO 2002 projections of natural gas demand) and in the MARKAL model.

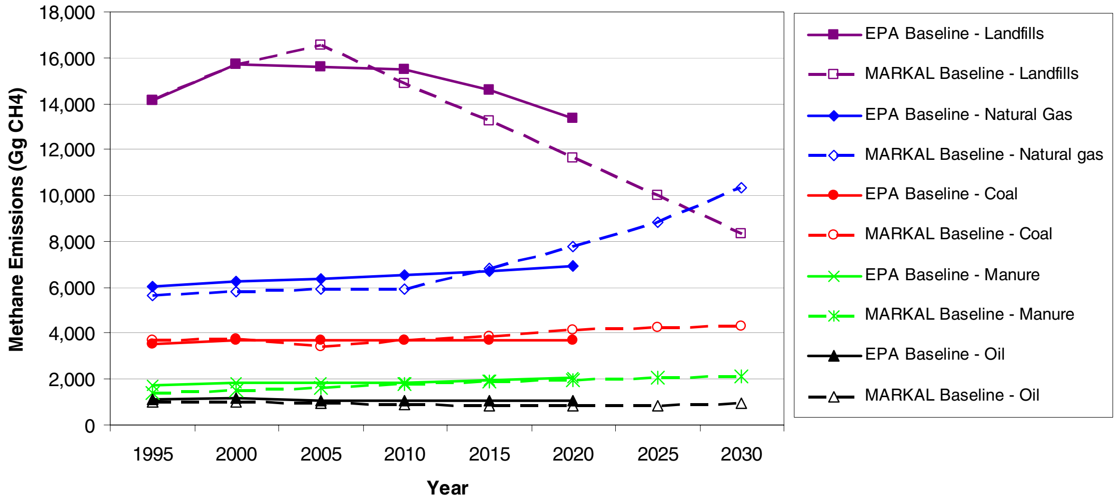


**Figure 2: Methane Subsystem Calibration to EPA Baseline Projections**

## Methane Mitigation Scenarios

Using this model, analyses were performed to investigate the effectiveness of various technologies and policies for reducing methane emissions. Specifically, the following five scenarios were run.

1. Methane Reference Case. As with the USEPA projections, this run contains no mitigation technologies and provides a baseline for evaluation of which mitigation technologies are most cost-effective. This serves as the calibration run.

2. Adoption of Cost-Effective Options. For this run, the mitigation technologies were added to the model and allowed to be selected by the model on a strict economic basis only. Comparison of this case to the Reference case provides a measure of the benefits that can be achieved by facilitating entry of all cost-effective technologies into the market.

3. Fuel price sensitivity. For this case the Adoption of Cost-Effective Options scenario was run using the AEO 2004 high oil and natural gas prices case.

4. Methane Reduction. For this scenario, three illustrative model runs were made in which methane emissions were reduced 10%, 25% and 50% below the level in the Adoption of Cost-Effective Options scenario, to be achieved in 2030 progressively from the 2005 level found in the Adoption of Cost-Effective Options run.

5. GHG Reduction. For this scenario, combined emissions of methane and $CO_2$ were modeled based on their relative global warming potential. A value of 21 was used for methane[10], and three illustrative emission reduction runs were developed of 10%, 20% and 30% in the same manner as the methane reduction policy run.

## Scenario Results

The Base case methane emissions are about 25.8 million metric tons (MMT) in 1995 which grow to about 28.5 MMT in 2005 before dropping somewhat to 26 MMT by 2030. Most of this reduction is due to decaying emissions in existing landfills, waste reduction programs and diversion of MSW from landfills to alternative uses

In the Adoption of Cost-Effective Options, the reference scenario for the sensitivity runs, shown in Figure 3, methane emissions increase from 1995 levels to a bit over 27 million metric tons (MMT) in 2005 and drop to about 21.5 MMT by 2030. Most of this reduction is due to cost-effective uses of on-site electricity generation using municipal solid waste (MSW) and landfill gas (LFG), dry seals on centrifugal compressors used in natural gas production, some coal mine degasification, and farm-scale electricity generation using manure digester technology in warm climates.

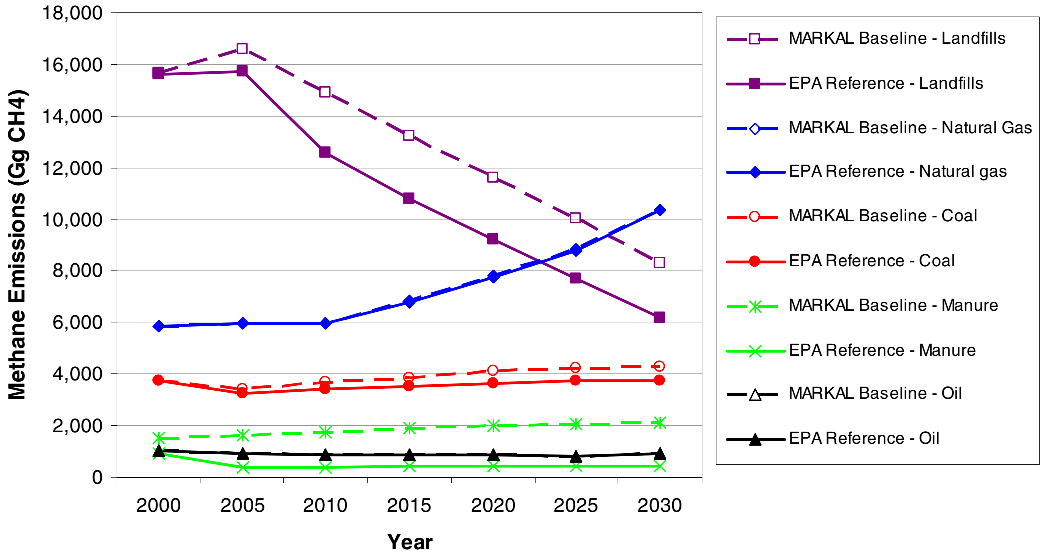


**Figure 3: Adoption of Cost-Effective Options - Reference Scenario (No Emission Constraints)**

Given the uncertainty in fuel prices, a scenario was developed based on the High Oil and Natural Gas Price scenario from the AEO 2004, where prices are approximately 1.35 times their base case values. In this scenario, the cost of all imported and domestic crude oil and all imported petroleum products as well as natural gas supplies were increased by this factor. This scenario is illustrated by Figure 4, where it can be seen that while there is a small additional reduction in the landfill and coal sectors, the methane emissions increase significantly in the natural gas sector because of the increase use of natural gas in place of imported petroleum products. What this figure does not show is that owing to the fuel prices, there is an increase in the number of MSW heat and power generation projects, and some coal mine degas capture projects. This trend continues when the GHG limit scenarios are combined with the higher oil and gas prices, with the most noticeable increase in the capture of methane from coal mines.

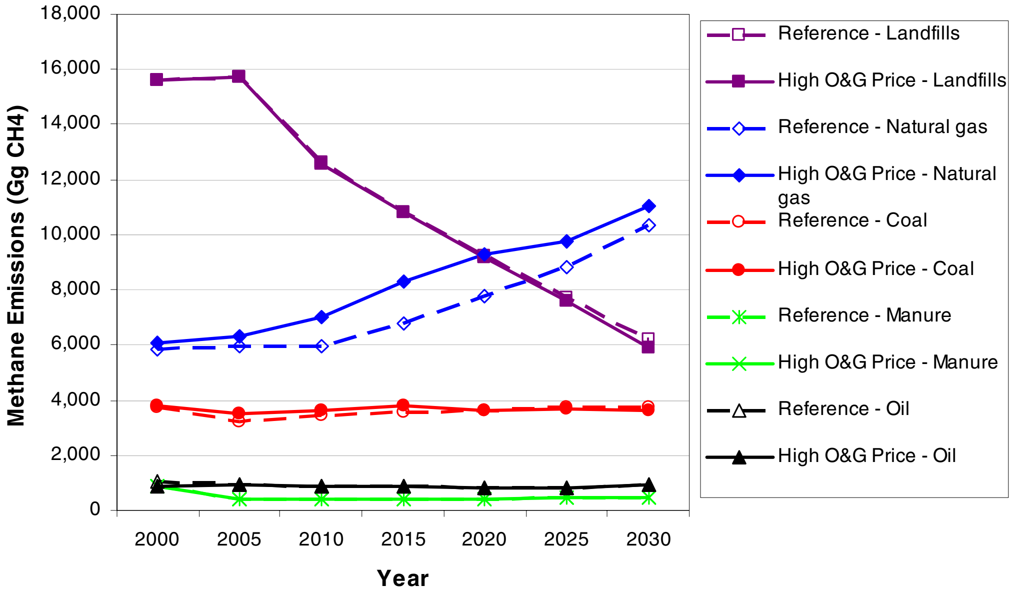


**Figure 4: Impact of High Oil and Gas Prices on Methane Emissions**

For the Methane Reduction scenario, three runs were made with reductions in methane emissions throughout the energy system starting in 2005. The reductions were made from the Reference case (the one permitting the adoption of cost-effective options) methane emission levels with target reductions of 10%, 25% and 50% being achieved in 2030 based on a linear ramp to the target level starting from period 2000 levels.

The result of these reduction runs is illustrated in Figure . With a 10% reduction, most of the additional methane reductions come from the coal sector, through the capture of gob gas from new mines, the utilization of coal mine methane (CMM) as supplemental fuel and the flaring of ventilation air. With a 25% reduction, more coal mine methane is flared and additional landfill gas is both flared and used for supplemental fuel. In addition, several mitigation technologies in the natural gas sector are utilized. This trend continues in the 50% reduction, where most of the additional methane reductions come from additional flaring of CMM and LFG, pretty much eliminating this as source of methane by the end of the modeling horizon, and though the increased use of mitigation technologies that eliminate natural gas releases.

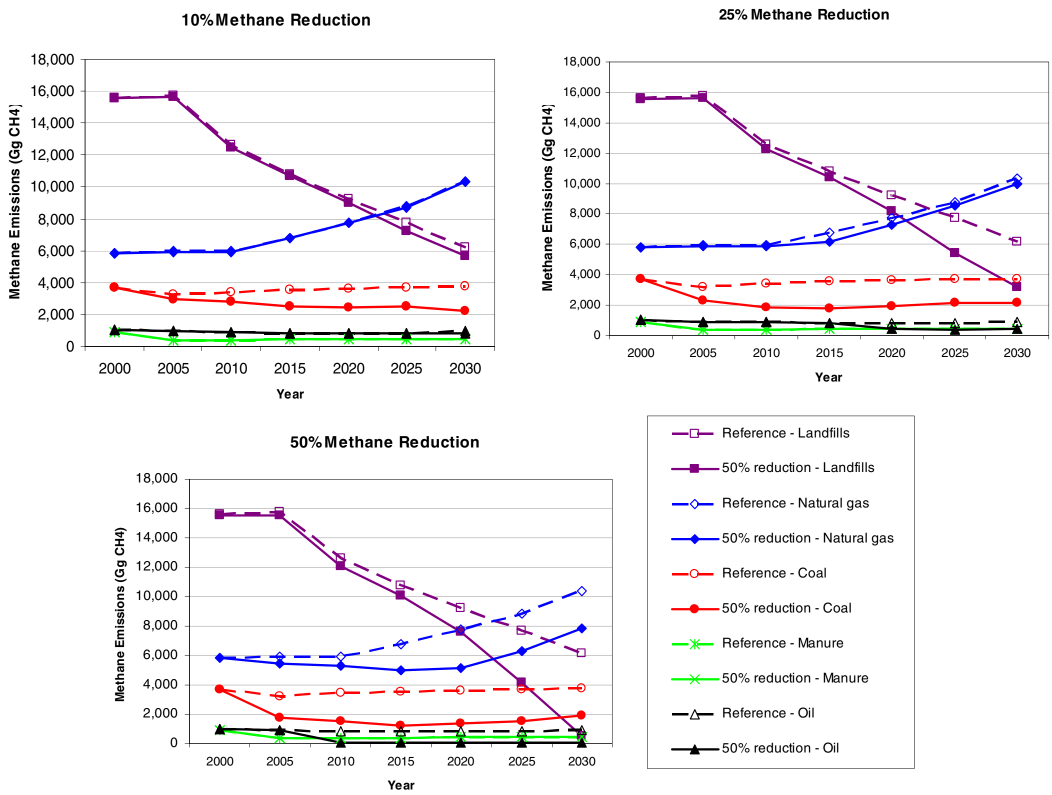


**Figure 5: Methane Reduction Scenario -10%, 25% and 50% Reductions**

In the GHG Cap scenario, the methane reductions come initially from the landfill and coal sectors. As the GHG reduction amount increases, the additional reductions continue to come from these two sectors along with reductions from the natural gas sector. Very little reductions come from the oil sector in this scenario compared to the Methane Reduction scenario.

For comparison purposes a 20% $CO_2$-only reduction run was made. The results of this scenario clearly illustrate the merits of bundling the GHG gases and striving to mitigate emissions collectively (i.e. on a carbon equivalent basis). The total system cost for the $CO_2$-only reduction scenario increased by 0.32% (78.7 billion1995$) over the Reference scenario, but in the combined GHG reduction scenario the total system cost increased by less than 0.08% (18.9 billion 1995$). In addition, the marginal costs for meeting the same GHG reduction target were lower in the combined GHG run for every period. For example, in 2020 the marginal methane reduction cost was $55/TCE compared to $70/TCE in the $CO_2$-only run. An analysis of the technologies deployed to reduce $CO_2$ emissions was not performed for this paper, but an analysis of the interaction between $CO_2$ mitigation and methane mitigation technologies could be the subject of future work.

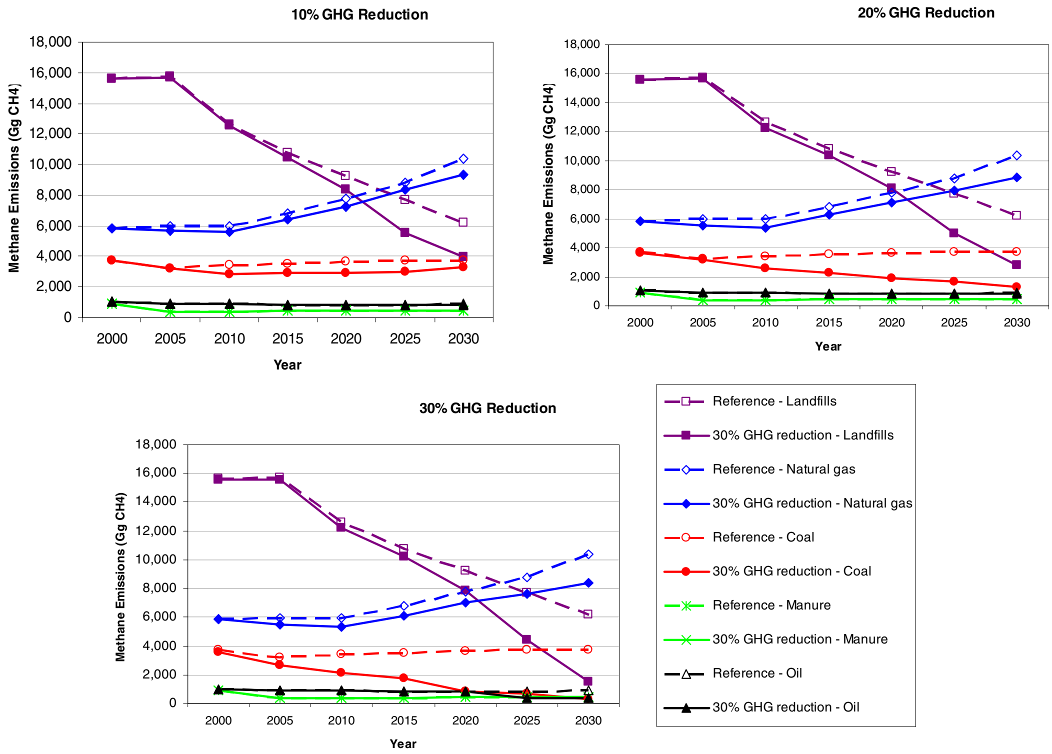


**Figure 5: GHG Reduction Scenario -10%, 20% and 30% Reductions**

## Marginal Abatement Cost Curves

The results of the scenarios discussed above were used to generate various forms of emission reduction cost curves. The most basic of these is the continuous emission reduction cost curve (CERC), shown in Figure 6 for methane, which illustrates the increase in total discounted system cost that results from the reduction in methane emissions, expressed in kilotons of methane (kt $CH_4$). A similar curve is also presented for **total** GHG emissions in Figure 7. Figure 7 presents the three Methane Reduction runs, the $CO_2$-only runs, and the three Combined GHG Reduction runs for a 10%, 25% and 50% reduction where the emissions are expressed in units of million metric tons of carbon equivalent (MMTCE). Each curve uses the Reference scenario as the common starting point. In the methane reduction runs, only methane is subject to the 10%, 25% and 50% cap though combined GHG emissions is shown in the graph. In the $CO_2$ only runs, only $CO_2$ is reduced. In the combined GHG scenario, overall emissions of methane and $CO_2$ are reduced. How much methane is reduced compared to $CO_2$ in the combined scenario depends on the cost effectiveness of the competing options.

The figure shows that the GHG emissions for the methane-only runs actually increase slightly before decreasing. This is due to both the combustion of mitigated methane adding to the accounting of $CO_2$ emissions, and the models choice to increase coal production and use relative to natural gas since more reductions of methane can be cost-effectively reduced from the coal sector. The figure also illustrates that the cost of achieving a 20% GHG reduction is lower in the GHG scenario than in the $CO_2$-only scenario.

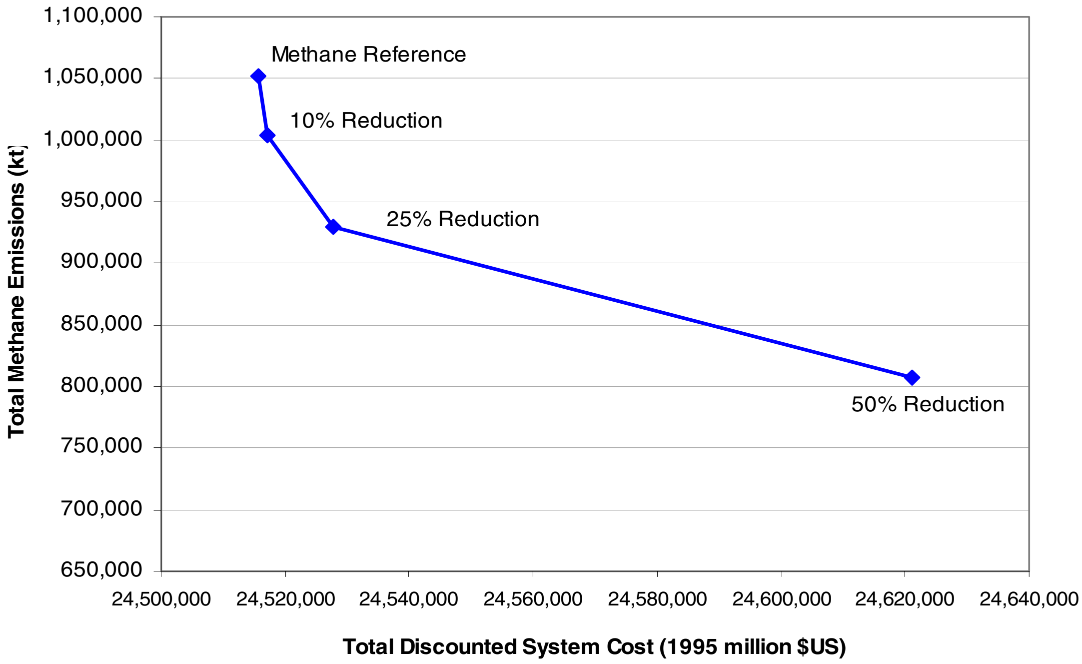


**Figure 6: Continuous Methane Emission Reduction Cost Curve**

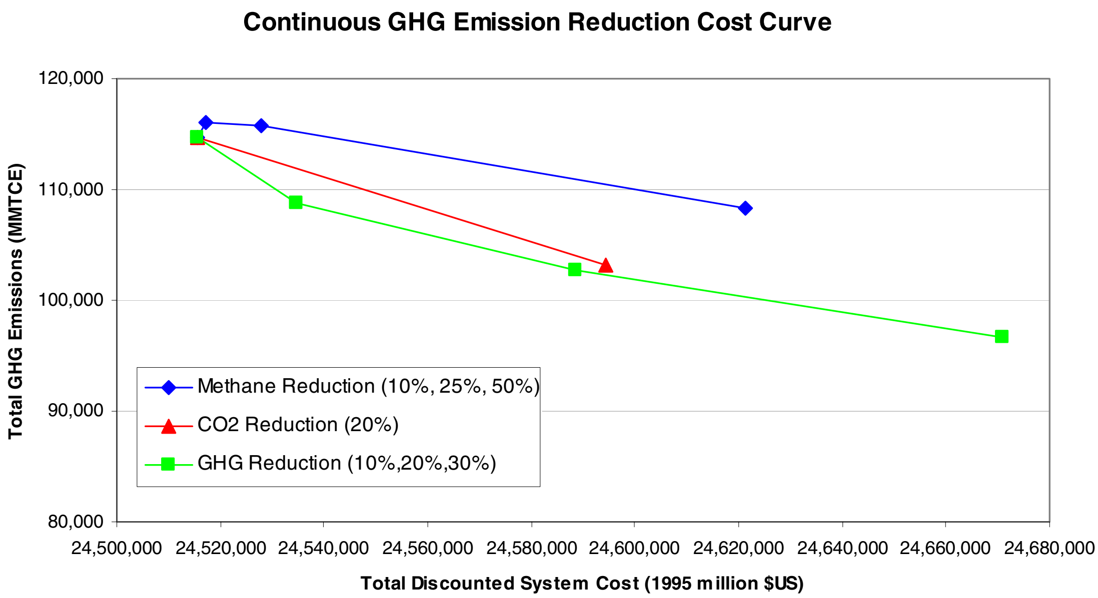


**Figure 7: Continuous GHG Emission Reduction Cost Curve**

The continuous emission reduction cost curves represent the action of the entire energy system, and simply shows the trade-off between total system cost verses total emissions, providing no insight into technology choices. However, since methane emissions and reductions are tracked at the technology level in this model we can also generate two other types of cost reduction curves that contain information on the specific mitigation options employed by the model. The incremental methane mitigation cost curve (IMCC), shown in Figure 8 for the three methane reduction runs, is developed by ordering the unit mitigation cost for each technology employed in an ascending order (cheapest to most costly) and plotting them against the cumulative amount of methane mitigation achieved. These curves differ from technology-based marginal abatement cost curves in that they illustrate only the options that are implemented in order to reach the target (not all potential options). Each of the curves is scenario specific as the timing of the investments (and thus the cost of each investment) is specific to the scenario.

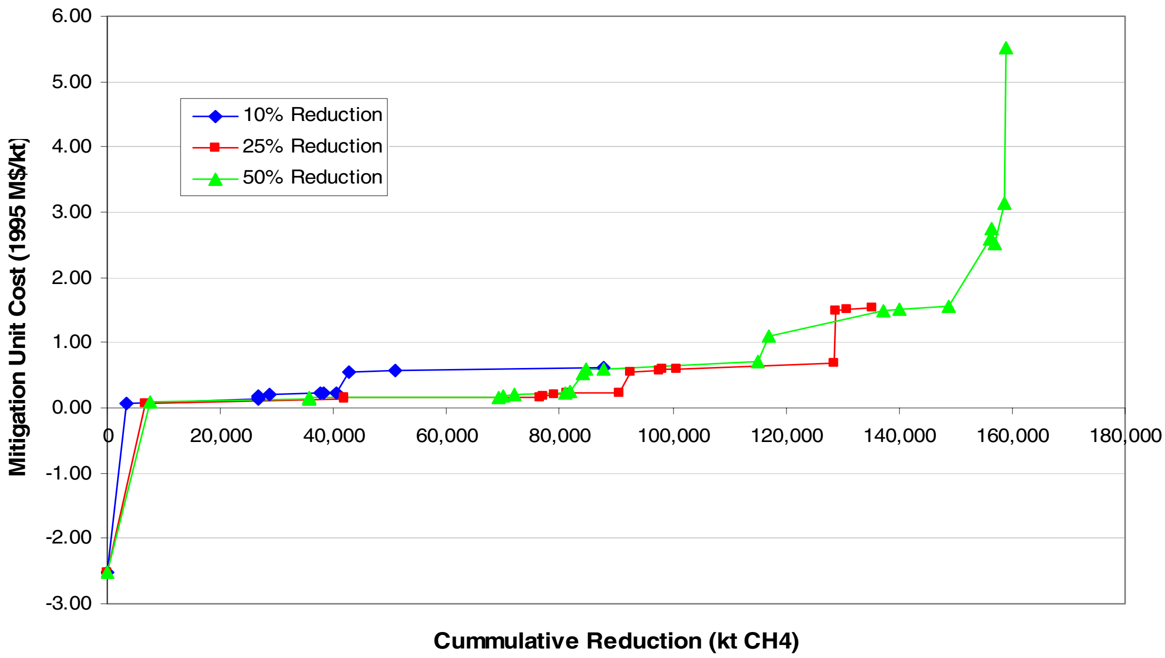


**Figure 8: Incremental Methane Mitigation Cost Curve - 2000 to 2030**

The cumulative methane mitigation cost curve (CMCC), shown in Figure 9, plots the cumulative cost of deploying each mitigation technology against the cumulative amount of methane mitigation achieved (ordered according to the same ascending order of methane mitigation unit cost). The curves in this plot also show some variations due to the timing of investments made by the model and variations in the utilization of the selected technologies. The figure shows that the mitigation technologies selected in the 10% reduction case are more expensive than in the other two cases. The cumulative costs of limited reductions are higher because larger investments yield larger per unit reductions. The timing and the magnitude of the investment affect the cost. When reductions are forced to be equal to 10%, cumulative costs for a level of reduction rise compared to the more stringent cases because investments are made to meet the caps in 2005, 2010, 2015, which are not used to their full capacity in later years. As the reduction becomes little more stringent, larger projects are implemented earlier, reducing cumulative costs. As a reduction cap becomes significantly more stringent, cumulative costs again rise as more expensive technologies need to be deployed to achieve the target.

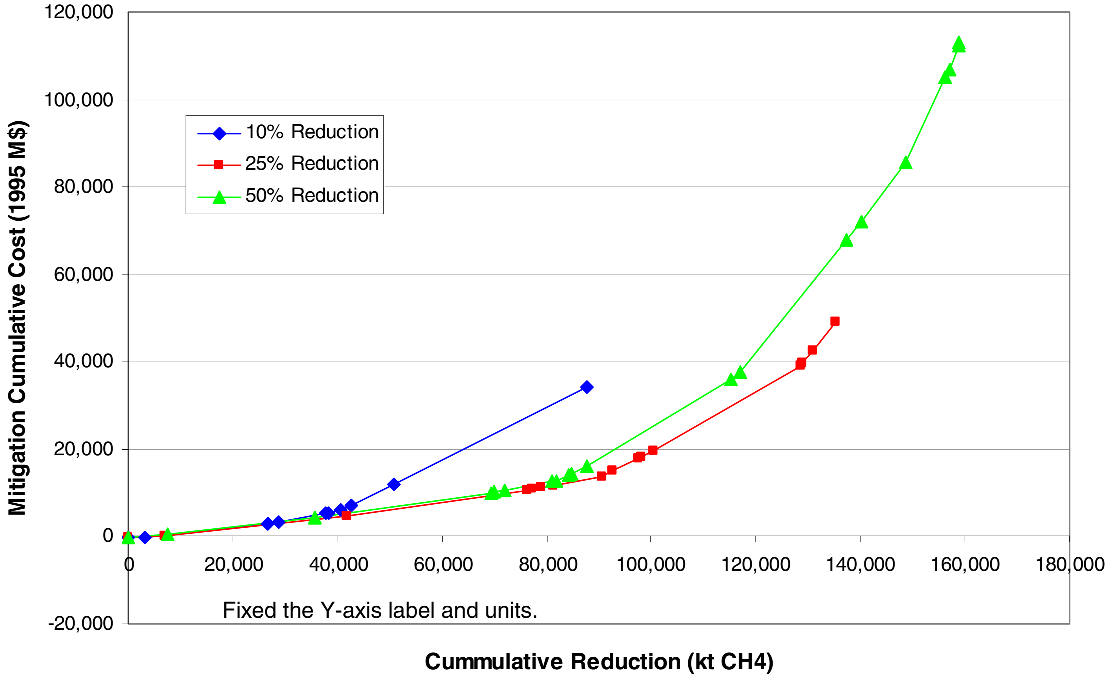


**Figure 9: Cumulative Methane Mitigation Cost Curve - 2000 to 2030**

Incremental and continuous methane mitigation cost curves were also generated for the three combined GHG reduction runs, as shown in Figure 11 and Figure 2, respectively. The curves for each of the three runs are much closer together. This indicates that the investments in methane mitigation technologies are run at their full utilization rates when decisions are based on the reduction of both $CO_2$ and methane emissions.

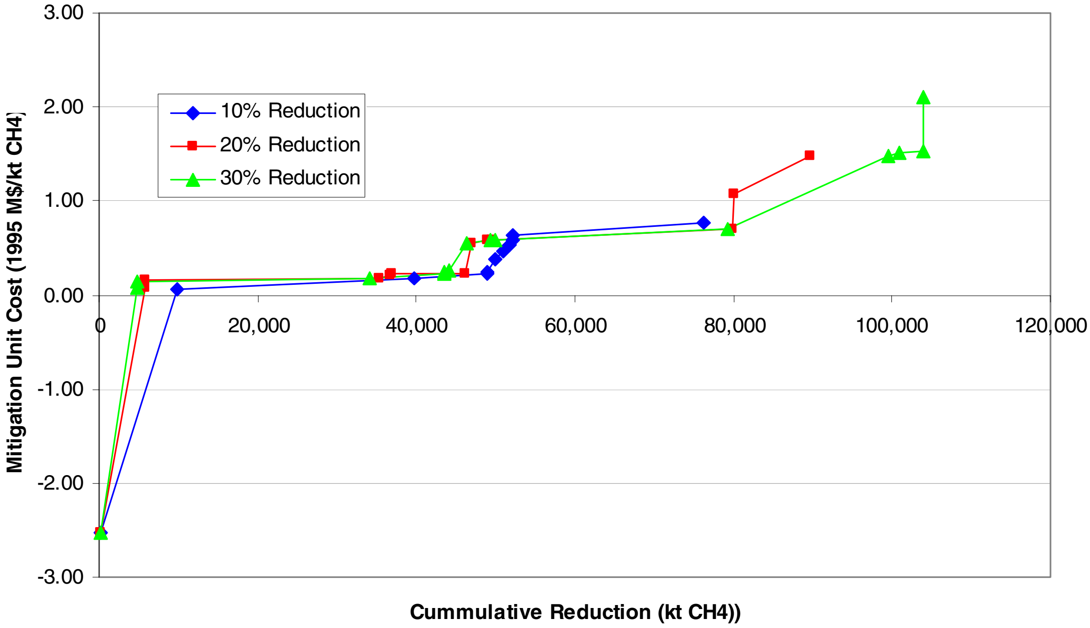


**Figure 10: Incremental Methane Mitigation Cost Curve - 2000 to 2030 (GHG Scenario)**

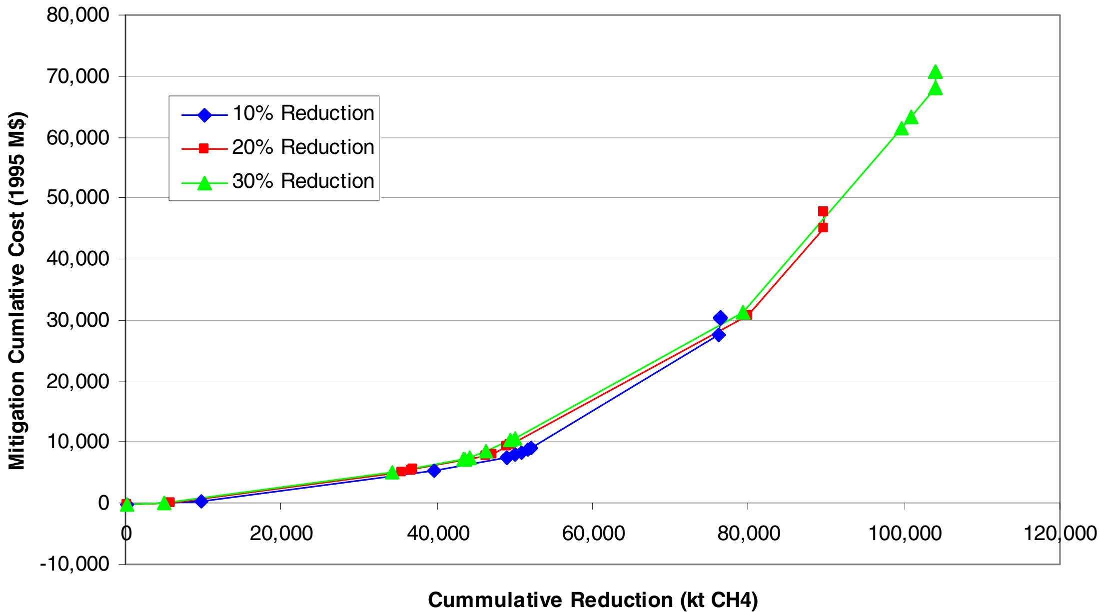


**Figure 12: Cumulative GHG Mitigation Cost Curve - 2000 to 2030**

Table 2 lists the principal methane mitigation technologies selected by the model to achieve emission reductions in all of the runs discussed above, ordered by their cost-effectiveness.

**Table 2: Mitigation Technology Cost Effectiveness (M$1995/kt)**

| **Technology** | **M$1995/kt** |
|---|---|
| Dry Seals on Centrifugal Compressors (Natural Gas Process & Transmission) | -2.52 |
| Process Heat Supply from Utilization of Coal Mine Methane | 0.08 |
| Flaring of Coal Mine Methane | 0.14 |
| Capture and Upgrade of Gob Gas from New Coal Mines | 0.15 |
| Flaring of Landfill Gas | 0.17 |
| Fuel Gas Blowdown Valves (Natural Gas Process & Transmission) | 0.18 |
| Capture and Upgrade of Gob Gas from Existing Coal Mines | 0.21 |
| Capture and Upgrade of Landfill Gas for Pipeline Injection | 0.23 |
| Electricity Generation using Landfill Gas | 0.53 |
| Low-bleed Pneumatic Devices (Natural Gas Production) | 0.59 |
| Landfill Gas used for Supplemental Fuel | 0.59 |
| Co-Generation using Landfill Gas | 0.72 |
| Co-Generation using Coal Mine Methane | 1.10 |
| Increased Oxidation Caps for Landfills | 1.48 |
| Flaring of Associated Gas – Onshore Oil Production - Alaska | 1.51 |
| Flaring of Associated Gas – Onshore Oil Production – Lower 48 | 1.57 |
| Utilization of Associated Gas – Offshore Oil Production – Lower 48 | 2.59 |
| Low-bleed Pneumatic Devices (Natural Gas Process & Transmission) | 2.74 |
| Utilization of Associated Gas – Offshore Oil Production – Alaska | 2.53 |
| Gas turbines replace reciprocating engines (Natural Gas Process & Transmission) | 3.13 |
| Electronic Monitor at Large Surface Facilities (Natural Gas Distribution) | 5.52 |

## Conclusions

This study illustrates the importance of including the Methane sub-model to the US EPA national MARKAL model, both to encourage the use of cost-effective energy supply options embedded within the methane system and when examining programs looking to mitigate GHG emissions. From the modeling point of view the complexities of the methane emission sectors and their interactions with the energy system are represented in appropriate detail. The scenarios investigated in this paper were exploratory and serve to illustrate the possible technology and policy options that can be investigated with the model; with the continuous, incremental and cumulative mitigation cost curves providing insight into programs that might stimulate the market to more quickly adopt the more cost-effective mitigation options.

More model development is planned to further refine the mitigation technology characterizations and improve the model calibration, especially in the landfill sector. A very powerful capability of the US EPA MARKAL model is its ability to model technology and policy options for both $CO_2$ and $CH_4$ mitigation based on their relative global warming potential. The results of the mitigation scenarios performed for this paper illustrate the increased cost-effectiveness of such combined strategies.

## References

[1] See www.etsap.org for a summary of MARKAL, its applications and its user community.

[2] *"Feasibility Study for the Inclusion of Industrial and Municipal Methane Sources in a MARKAL Model".* Preliminary concept developed by Lorna A. Greening, deliverable under U.S. Environmental Protection Agency Contract No. 68-W7-0067, TO 4004, Task #5, September 26, 2001.

[3] The methane subsystem as model is essentially self-contained, and can be hooked into most MARKAL models by simply renaming the energy carriers at the subsystem borders (e.g., mined coal, oil production, pipeline gas, etc.). Emission profiles for landfills and manure treatment, and the technology costs, need to be adjusted to the local circumstances.

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[8] The U.S. Landfill Rule requires landfills with a certain level of waste-in-place to flare landfill gas in order to control for Volatile Organic Compounds (VOCs).

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[10] Based on the Second Assessment Report of the Intergovernmental Panel on Climate Change.