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Variability and Uncertainty in the Cost of Saline Formation Storage

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Abstract

Cost estimates for CO_2 capture and storage (CCS) systems typically focus on details of the CO_2 capture process and make simplistic assumptions about the cost per ton of CO_2 for the transport and storage components of the system. These ad hoc assumptions ignore the large variability in the storage cost from site-to-site caused by variation in storage reservoir characteristics. Moreover, the typical costs of storage that are widely applied in CCS cost estimates do not fully consider the cost of site characterization and operational monitoring. To address this problem, we have recently developed an engineering-economic model for geological storage in deep saline formations. In this paper we briefly describe the newly-developed performance and cost models for CO_2 storage in deep saline formations, and use these models to develop a range of cost for CO_2 storage. The range of cost is explored using four cases, representing different types of potential storage reservoirs. Results from the four case studies show considerably different capital costs and, consequently, levelized costs of CO_2 stored. In addition, the sensitivity of CO_2 storage cost to variability and uncertainty in model input parameters for one of the case studies is examined. These results show clearly that the cost of CO_2 storage in saline formations is most sensitive to factors affecting site characterization costs, which have been significantly underestimated in most past studies, and are highly dependent on future regulation of geological storage projects.

Keywords: carbon capture and storage; geologic sequestration; carbon dioxide; storage economics.

1. Introduction

There are numerous options for geologic sequestration of carbon dioxide (CO_2) [1] and, while there is considerable uncertainty over the total capacity available for sequestration [2], it is clear that saline aquifers offer the largest potential for long term storage. While there are many analogues to CO_2 storage, such as acid gas injection [3, 4], natural gas storage [5, 6], disposal of treated wastewater [6, 7], and disposal of hazardous waste [6], there are still many gaps in our understanding of CO_2 storage processes, including the cost of storage [1].

The objective of this paper is to present the development of a model that will allow the cost of CO_2 storage to be estimated given the specifics of a storage site. The cost estimates for CO_2 storage are embodied in an engineering-economic model that is used to assess the sensitivity of storage cost to changes in geological settings and other

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assumptions. This analysis will also show the potential range of costs that could occur and the probability associated with these costs for a given scenario.

2. Model Description

The model of the aquifer storage process presented here can be separated into two parts: a performance model, and a cost model. As shown in Figure 1, the performance model takes inputs that describe reservoir and brine properties, the development of the storage field, and the time horizon of interest. From these inputs the model estimates the number of wells required to achieve the desired injection over the planning horizon, the required wellhead pressure to achieve this rate, and the additional compression energy required (if any) to meet this wellhead pressure.

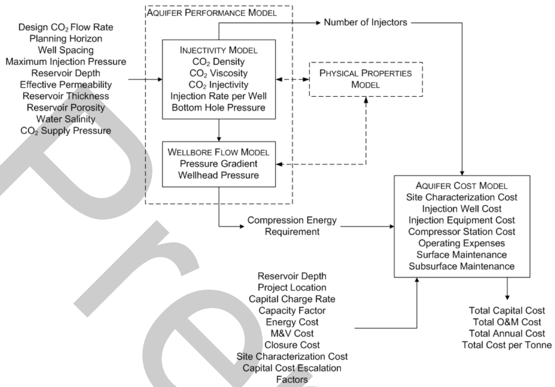

Figure 1. The aquifer storage engineering-economic model described here.

Injection of millions of tonnes per year of CO_2 into an aquifer will require multiple injection wells in most cases. A scenario with multiple injection wells (i.e. injectors) is more complex than a similar scenario with only one injector because the pressure field generated by any well will interact with the pressure field of every other injector. Thus, the interactions between multiple injection wells injecting CO_2 into the same confined aquifer must be considered when estimating the injectivity of the injection well system.

For a generic two-well system, the sum of the effects of injecting off-center into a region with a circular constant pressure boundary and of well 2 on well 1 is given by [8]:

$$\frac{2\pi k_{h,eff} b}{\mu}\left(p_{wb,1} - p_e\right) = q_1 \ln\left[\frac{r_e}{r_w}\left(1 - \frac{d_1^{\,2}}{r_e^2}\right)\right] + \frac{q_2}{2}\ln\left[\frac{d_2^2 d_1^2 + r_e^2\left(r_e^2 - d_2^2 - d_1^2 + r_{1,2}^2\right)}{r_{1,2}^2 r_e^2}\right] \tag{1}$$

Similarly for well 2, the above equation can be written [8]:

$$\frac{2\pi k_{h,eff} b}{\mu}\left(p_{wb,2} - p_e\right) = q_2 \ln\left[\frac{r_e}{r_w}\left(1 - \frac{d_2^{\,2}}{r_e^2}\right)\right] + \frac{q_1}{2}\ln\left[\frac{d_2^2 d_1^2 + r_e^2\left(r_e^2 - d_2^2 - d_1^2 + r_{1,2}^2\right)}{r_{1,2}^2 r_e^2}\right] \tag{2}$$

where, in both of the above equations: $k_{h,eff}$ is effective permeability in the horizontal direction (m^2); b is effective thickness of the aquifer (m); μ is viscosity of the injected fluid (Pa·s); p_{wb} is the well bottom pressure at the wellbore face (pa); p_e is the pressure (pa) at the system boundary of radius r_e (m); q is the injection rate (m^3/s); r_w is the wellbore radius; d is the distance between the center of the constant pressure system and the wellbore (for well 1 or 2 as denoted by the subscript); $r_{1,2}$ is the distance between wells 1 and 2.

Equations 1 and 2 form a linear system that allows the BHIP to be related to the system geometry, aquifer properties, and injection rates for the two-well example. This linear system can be extended to a generic system of *n* wells by writing the equation $\overline{A} \cdot \vec{x} = \vec{b}$, where $\overline{A}$ accounts for the geometry of the system; $\vec{x}$ contains the injection rates for each well; and, the $\vec{b}$ accounts for the pressure at each well and the geological properties of the aquifer [8]. Therefore, for a specified geometry, BHIP for each of n-wells, and aquifer properties, the injection rate for each of n-wells can be calculated by inversion of $\overline{A}$ followed by multiplication by $\vec{b}$ or a number of more efficient methods

The injectivity of the linear system as a function of the number of wells and system geometry can be generalized to any set of aquifer properties by using the dimensionless injectivity, i_d. For well n, the dimensionless injectivity is defined as [9]:

$$i_{d,n} = \frac{q_n \mu}{2\pi k_{h,eff} b (p_{wb,n} - p_e)} \tag{3}$$

If it is assumed that the BHIP, $p_{wb,n}$, at each injection well is equal—which appears to be the configuration that maximizes the sum of the $i_{d,n}$ for the n-well system—the dimensionless injectivity for each well can easily be calculated [8]. Figure 2 shows the average, minimum, and maximum dimensionless well injectivity in systems with 1 to 100 wells with 40-acre well spacing.

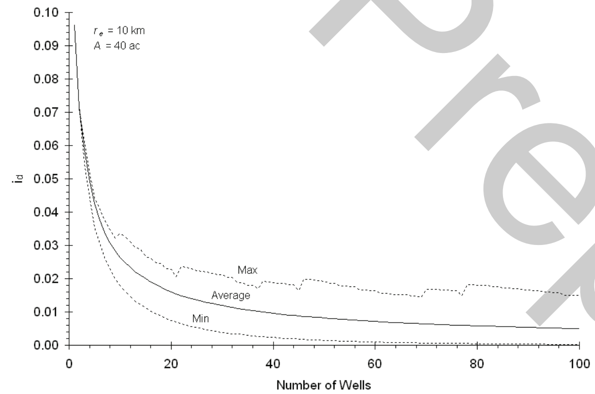

Figure 2. Average, minimum, and maximum injectivity for systems with 1 to 100 wells on 40 acre spacing, and a constant pressure radius where pe = pi at 10 km.

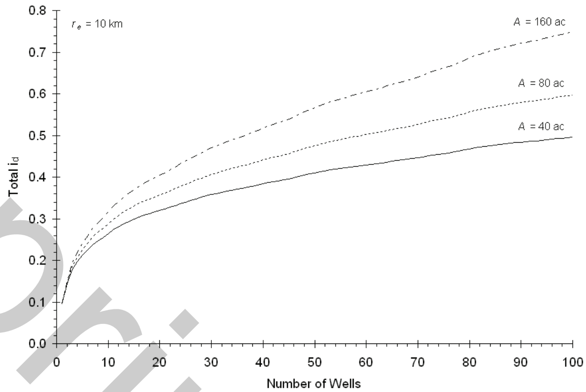

Figure 3. Total injectivity for systems with 1 to 100 wells on 40, 80, and 160 acre spacing with a constant pressure radius where $p_e = p_i$ at 10 km at left.

Figure 2 clearly shows that the addition of wells to the system decreases the average, minimum, and maximum well injectivity in the system. The well with the minimum injectivity is always the well at the center of the system, while the well with the maximum is always on the perimeter of the system. The decrease in the average injectivity of individual wells with the addition of more wells (Figure 2) means that the there are diminishing returns from adding wells to a system. Figure 3 shows the cumulative injectivity of systems with 1 to 100 wells for three different well spacings.

The pressure at the well bottom, p_{wb}, used in Equations 1 and 2 is estimated from a correlation developed using a numerical model that considers pressure changes due to hydrostatic head, friction losses, and heat transfer [8]. The effective permeability is estimated from the average permeability and the Dykstra-Parsons coefficient assuming that the reservoir can be represented by a layered system [8].

The economics model developed for aquifer storage of CO_2 takes a number of inputs (shown in Figure 1), along with the performance model results, to estimate the levelized cost of CO_2 storage. The costs associated with the project can be divided into capital and operating costs. Capital costs for saline aquifer storage consist of four elements: one-time site characterization costs; project capital costs; operating and maintenance (O&M) cost; and, monitoring, verification, and closure costs. Operating and maintenance costs for an aquifer storage project include expenses for labor, chemicals, and other consumables, plus expenses for surface equipment and subsurface equipment maintenance, including periodic well workovers. If CO_2 recompression is required, the cost of energy to operate the compressors is also and O&M cost.

The primary factor affecting the cost of site characterization is the size of the area of review. (AoR) Nordbotten et al. proposed a method to estimate the aerial extent of plume spread in CO_2 storage [10] and this method is used to estimate the required AoR for a storage project over the specified planning horizon. Costs associated with characterizing this area are assumed to be: \$100,000 per square mile (mi^2, \$38,610 per km^2) for geophysical characterization (3-D seismic); \$3,000,000 to drill and log a well; and an additional 30% of these total costs for data processing, modeling, and other services [11]. One well would be required for every 25 mi^2 (65 km^2) of the review area [11].

The project capital cost is estimated based on the costs for drilling and completion (D&C); injection equipment (e.g., wellhead, flow and control equipment, distribution piping, etc.); and, compression equipment. These capital costs are amortized over the life of the field using the project discount rate. Regressions relating the components of capital cost to reservoir depth have been developed from a number of data sets, and take an exponential form:

$$C = a_1 e^{a_2 d} \tag{4}$$

In Equation 4, C is the component capital cost, d is the reservoir depth in meters, and a_1 and a_2 are regression coefficients.

The regression for D&C cost was developed using data from the 2001 Joint Association Survey on Drilling Cost [12], while the costs for production well equipment, injection well equipment, and lease equipment were developed from Energy Information Administration survey data [13]. Regression coefficient estimates are given in Table 1, and yield capital costs in 2004 U.S. dollars. The generalized model given in Equation 4 accounts for a large proportion of the variation in the data sets as reflected by an adjusted-r^2 value of greater than 0.90 for most cost component regressions.

Table 1. Capital cost categories included in the model, their regression form, and the associated regression coefficient estimates for each region in the model. All capital costs are in 2004 U.S. dollars.

	Drilling & Completion		Injection Well Equipment	
	Exponential		Exponential	
Region	a_1	a_2	a_1	a_2
W-TX	\$122,555	8.04×10^{-4}	\$31,226	2.81×10^{-4}
S-TX	\$136,434	8.04×10^{-4}	\$37,040	1.16×10^{-4}
S-LA	\$190,790	8.04×10^{-4}	\$39,876	1.13×10^{-4}
MCR	\$110,907	8.04×10^{-4}	\$39,876	1.13×10^{-4}
RMR	\$178,547	8.04×10^{-4}	\$29,611	2.60×10^{-4}
CA	\$165,290	8.04×10^{-4}	\$38,931	2.10×10^{-4}
AK*	\$531,697	8.04×10^{-4}	\$38,931	2.10×10^{-4}
APPL†	\$88,263	8.04×10^{-4}	\$39,876	1.13×10^{-4}
OTHR†	\$110,907	8.04×10^{-4}	\$39,876	1.13×10^{-4}

In cases where the pipeline pressure is insufficient for CO_2 injection, a compressor must be added at the storage site. The total capital cost of a reciprocating compressor station has been estimated by the International Energy Agency (IEA) in a European study of the pipeline transmission of CO_2 [14]. That compressor cost model was also used in earlier in the pipeline transport model (see Section 2.2.3), and is given by Equation 5:

$$C = 8.35P + 0.49 \tag{5}$$

where, C is the compressor capital cost in millions of U.S. dollars (2004) and P is the installed booster station power in MW. This correlation yields a unit cost of \$8,346 per kW of installed capacity.

Operating and maintenance (O&M) costs for an aquifer storage project include expenses for labor, chemicals, and other consumables, plus expenses for surface equipment and subsurface equipment maintenance, including periodic well workovers. O&M costs for CO_2 injection are assumed to be comparable to the costs of water injection for secondary oil recovery (allowing for increased well workover costs), and are based on the Energy Information Administration survey data [13]. If CO_2 recompression is required, the cost of energy to operate the compressors is also an O&M cost.

3. Case Study—Deterministic Results

The engineering-economic model has been applied to four cases, the names and key parameters of which are listed in Table 2 (see elsewhere for a full description of the reservoirs and projects [8]). The Texas South Liberty-Frio and Alberta Lake Wabamun-Manniville cases have been identified as potential targets for large-scale geological sequestration [15-18]. The Oklahoma North Purdy, Springer A and Alberta Joffre-Viking cases are based on oil fields, but treated as aquifers with equivalent petrophysical properties for this study. These four aquifers are all sandstone bodies, with depths greater than 1 km and *kh* from 4,500 to 940,000 md·ft.

Table 2. Key performance model parameters for the four case studies [8].

Parameter	Northeast Purdy Unit	Joffre Viking Pool	South Liberty	Lake Wabamun Area
Location	Oklahoma	Alberta	Texas	Alberta
Unit	Springer "A" Sandstone	Viking Aquifer	Frio Formation	Mannville Aquifer
Well Spacing (acres)	80	80	80	80
CO_2 supply pressure (MPa)	10.3	10.3	10.3	10.3
$P_{wb,max}$ (% of p_{frac})	90%	90%	90%	90%
Depth (m)	2,499	1,500	1,850	1,514
p_{res} (MPa)	21.0	7.8	15.2	14.4
T_{res} (K)	338	329	329	327
k_h (md)	44	507	944	23
Net Sand (m)	91	30	300	59
ϕ (%)	13.0%	13.0%	27%	11.2%
x_{brine} (ppm_w)	100,000	40,000	100,000	68,074
V_{DP}	0.82	0.70	0.67	0.92

Each of the cases was evaluated with a project capacity factor (i.e. the percentage of the design capacity actually used on an annual basis) of 100% across a range of injection rates—5 Mt CO_2 per year being roughly equivalent to the amount of CO_2 captured from an 800 MW coal-fired power plant—with a time horizon of 10 years used to calculate the drainage radius, r_e [8]. The cost model parameters used in the case study are listed in Table 3 and are the same for each case for ease of comparisons. The capital recovery factor will be varied parametrically as part of the analysis.

The levelized cost of CO_2 storage predicted by the aquifer storage model is presented in Figure 4 for the four cases across a range of mass flow rates. For a design injection rate of 5 Mt CO_2 per year, the levelized cost of CO_2 storage is \$0.80 per tonne CO_2 for the Purdy-Springer case; \$8.86 per tonne CO_2 for the Joffre-Viking case; \$0.38 per tonne CO_2 for the Liberty-Frio case; and, \$0.76 per tonne CO_2 for the Lake Wabamun-Mannville case. Figure 5 shows the same results on an expanded scale for the three lowest-cost sites.

Several observations can be made from these figures. First, the levelized cost of storage in the Joffre-Viking case is substantially higher than for any of the other cases (Figure 4). Second, the three "low-cost" cases show different behavior with increasing injection rates: the storage cost for the Liberty-Frio case continually declines over the range shown, whereas the cost for both Lake Wabamun-Mannville case and the Purdy-Springer case goes through a minimum at between 2 and 3 Mt CO_2 per year (shown most clearly by the smoothed curves in Figure 5).

Table 3. Key economics model parameter values used in the four case studies.

Project Parameter	Deterministic Value
Capital Recovery Factor (%)	15
O&M Costs	
Compression Energy Cost ($/MWh)	40
Operating Monitoring & Verification ($/tonne)	0.02
Injection Fee ($/tonne)	0
Closure Cost ($)	0
Capital Cost Escalation Factors	
Drilling & Completion	1.0
Injection Well Equipment	1.0
Compression Equipment	1.0
O & M Cost	1.0

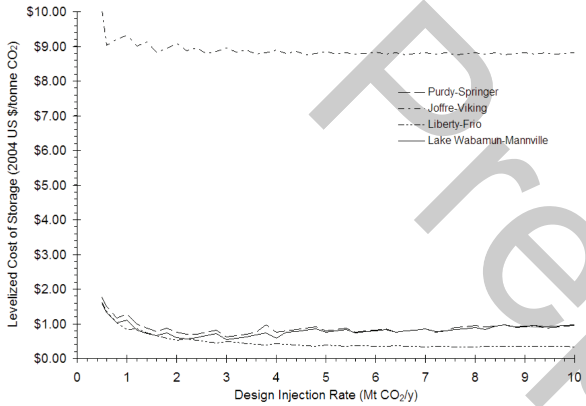

Figure 4. Levelized cost of CO_2 storage for the four cases across a range of design injection rates.

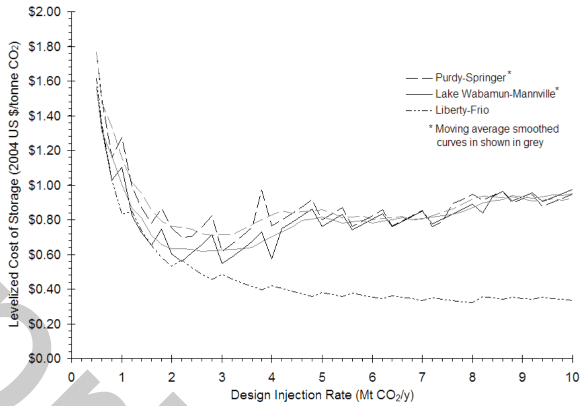

Figure 5. Levelized cost of CO_2 storage for the three low-cost cases shown at left across a range of design injection rates. Smoothed curves are shown in grey for the Purdy-Springer and the Lake Wabamun-Mannville cases.

These differences in cost can be explained largely by examining the breakdown of total capital cost for the projects: the fraction of the total capital cost associated with site characterization ranges from 49% to 99% for Liberty-Frio and Joffre-Viking cases, respectively. For the Joffre-Viking case the cost of site characterization represents nearly all of the capital cost because the aquifer properties (i.e., underpressured, relatively thin net sand, and high permeability) results in an abnormally large footprint for site characterization (i.e., almost 2600 km^2). Conversely, the cost of site characterization for the Liberty-Frio site is much lower, despite the high permeability of the Frio Sandstone, because of the expansive net sand (i.e. aquifer net thickness), which translates into a relatively small footprint (i.e., less than 50 km^2). The Purdy-Springer and Wabamun Mannville cases are intermediate between these two cases; the cost of compression equipment being a more significant factor. As the CO_2 injection rate increases, a trade-off between site characterization cost and compression cost (including resulting energy cost) occurs in the two intermediate cases, resulting in the minimums shown in Figure 5.

4. Case Study—Sensitivity Analysis

To assess the sensitivity of the model to changes in multiple performance and economic parameters, uniform distributions were assigned to a number of parameters and the model was used to estimate the levelized cost of CO_2 storage for the Lake Wabamun-Mannville case. Twelve performance model parameters and seven cost model parameters were assigned distributions and used to generate 1,000 Monte Carlo trials; both the parameters and the distributions for the parameter values can be found elsewhere [8].

Figure 6 shows the CDF for the levelized cost of CO_2 storage. The median cost of CO_2 storage is \$0.96 per tonne CO_2, with a 90% confidence interval of \$0.53 to \$2.15 per tonne CO_2. These results exclude 448 cases where the model could not meet the required injection rate using fewer than 100 injectors. In such scenarios, a project developer would likely look at other sequestration targets or use horizontal drilling to reduce the number of wells required.

Results of the Monte Carlo trials can also be used to assess the sensitivity of storage cost to the model parameters assigned uniform distributions. The measure used to assess the sensitivity is the Spearman rank-order correlation (r_s) [19]. The value of the rank order correlation coefficient for each model parameter is shown in Figure 7. The dashed vertical lines to the left and the right of the y-axis indicate the 5% significance level ($r_s = \pm0.09$); thus, rank-order correlation coefficients smaller than this value are not statistically significant at the 5% level. Figure 7 shows that the strongest correlation with the levelized cost of CO_2 storage is the effect of the effective permeability (r_s = -0.62) and, followed by the capital recovery factor (r_s = 0.40), net sand (r_s = -0.22), planning horizon (r_s = 0.15), porosity (r_s = -0.12), and the geophysical characterization cost (r_s = 0.11). The other rank-order correlation coefficients are not significant.

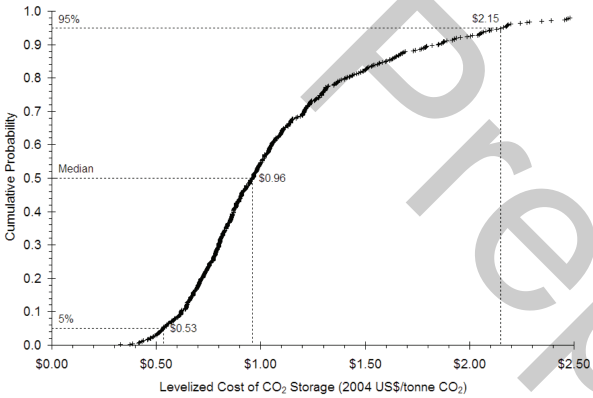

Figure 6. CDF for the levelized cost of CO_2 storage for the Lake Wabamun-Mannville case.

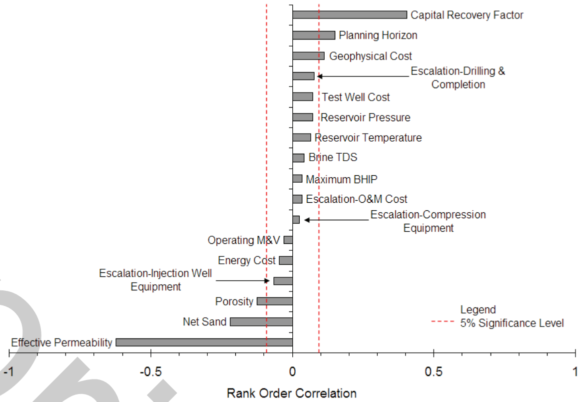

Figure 7. Rank-order correlation between the results of the Monte Carlo sensitivity analysis and the parameters assigned uniform distributions.

5. Conclusion

Results from these case studies show a large range of variability in the cost per tonne of CO_2 stored, driven primarily by differences in aquifer geology and petrophysical properties. For a design injection rate of 5 Mt CO_2 per year, the levelized cost of CO_2 storage ranges from \$0.38 per tonne CO_2 for the Liberty-Frio case to \$8.86 per tonne CO_2 for the Joffre-Viking case. Considering only the costs of well drilling and completion, and injection equipment, the capital cost of all of the cases was relatively similar; however, inclusion of the cost of site characterization changed the results greatly. For all of the cases, the largest single component of the total levelized cost was the cost of site characterization. The importance of assumptions regarding site characterization cost (and the implied methods of site characterization) to the levelized cost of CO_2 storage in saline aquifers has not been previously demonstrated.

The large contribution of site characterization cost to the levelized cost of storage implies that requirements for site characterization imposed by a regulatory framework should be carefully considered. Requirements for high-resolution characterization methods (e.g. 3D-seismic, as assumed here) or a larger AoR will increase the levelized cost of storage. The upfront cost requirements for characterization could be managed through an adaptive process, for example, by limiting the area of review to the area impacted for a specified time horizon (e.g., the planning horizon for a project), with provision for further characterization prior to extension of the operation past the original planning horizon.

6. Acknowledgements

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