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Holistic Approach for CO_2 Underground Geological Storage

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Abstract

Planning a carbon capture and storage (CCS) project that meets economic criteria and minimizes risk requires a systematic analysis of the full-value chain, including capture, transport, storage, formation characteristics, well number and type, formation integrity, well integrity, and monitoring, as well as abandonment, government regulations, and public constraints. The complex process of planning a CCS project that meets multiple objectives and honors multiple constraints involves a large number and variety of decisions. This paper describes the use of front-end loading (FEL) and a fully-integrated asset model (IAM) to address these issues. It includes a study example of a coal-fired power plant and assessment of multiple storage sites, including saline aquifer and enhanced oil recovery candidates.

Keywords: CO_2, modeling, storage, EOR, saline aquifer

Introduction

Planning a carbon capture and storage (CCS) project that meets economic criteria and minimizes risk requires a systematic analysis of the full value chain, including capture, transport, storage, formation characteristics, well number and type, formation integrity, well integrity, and monitoring, as well as abandonment, government regulation, and public constraints. The complex process of planning a CCS project that meets multiple objectives and honors multiple constraints involves a large number and variety of potential decisions that can compromise, delay, halt, or jeopardize the entire project. This paper describes of the use of FEL and a full IAM used as major components of a planning process. The paper also includes a study example for an integrated gasification combined cycle power plant that demonstrates the approach.

FEL is a best-practice, capital-planning process (Figure 1) that enables a systematic, holistic evaluation that provides full-cycle economics and risk analyses for a suite of project scenarios [1]. FEL is used extensively in capital industrial planning and in the oil and gas industry [1, 2]. FEL can also be a valuable planning process for CCS. The FEL process includes visualization, conceptualization, and definition phases. These phases are conducted with increasing project detail and complexity. Figure 1 shows an overview of the FEL process and the value added in each stage. The most valuable applications of FEL have used an IAM, that is, a model that represents the entire asset value chain of plant, pipeline, storage assessment, wells, operations, and economics. The IAM utilizes a physics-based numerical model.

This paper describes an optimization of the decision-making process for geological CO_2 storage, which minimizes risk, costs, and effort. This paper sets up a challenging storage example for a coal-fired plant, introduces an IAM, and then presents some results for the example.

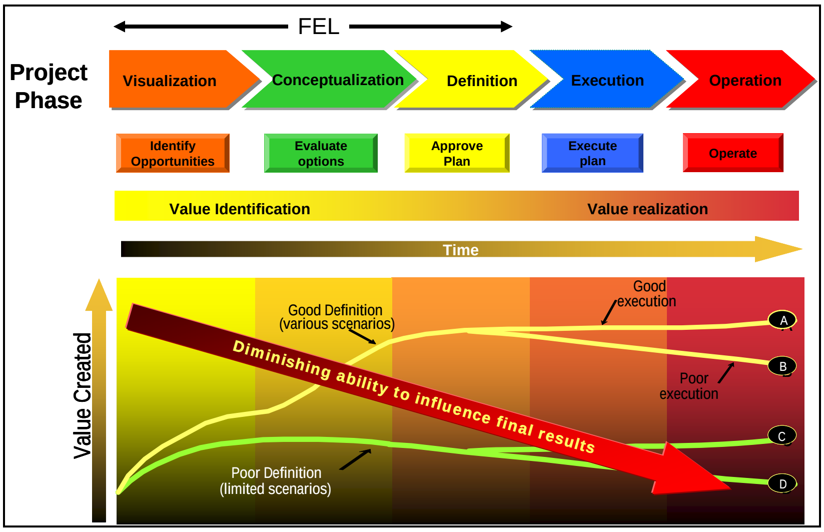


Figure 1 Overview of the FEL decision process and the value added.

CCS Example

The CSS example is synthetic but is representative of characteristics that are, and will be, typical for CCS projects. This example assumes a 550-MW power plant that must store two million tons of CO_2 per year for a 30-year period (approximately 30 billion standard m^3 CO_2). There are candidate sites that the power company can consider. Figure 2 illustrates two candidate saline aquifers and two candidate producing oil fields. A quick assessment of the situation shows the characteristics in Table 1. The power company has a portfolio of options with tradeoffs in storage capacity, capital investment, required infrastructure, and economics. It is assumed that at this stage of assessment, the saline aquifers have not been appraised in detail and are known from regional geologic studies. Decisions have to be made with assessments on risk as to selection of site, type of injection facilities and wells, process for injection (i.e., aquifer or oil recovery). There are also many uncertainties in the system with respect to formation characteristics, logistics, costs, etc. There is risk in each project as to storability and seal characteristics (see Cavanagh et al [3, 4]). The evaluation of decisions and uncertainties will be discussed in the next IAM section.

Table 1 Characteristics of the CCS project candidate sites.

	Local Aquifer	Distant Aquifer	Onshore O&G	Offshore O&G
Distance from source	15 Km	160 Km	250 Km	320 Km
Capacity	++	+++	+	++
CAPEX	$$$	$$$$	$$$	$$$$
Revenue	$	$	$$$	$$

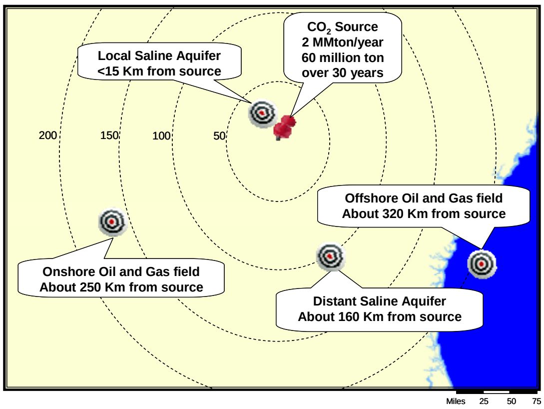


Figure 2. Schematic map of the CO_2 source and potential storage sites.

Integrated Asset Model

The IAM combines the components of the evaluation into a single model, and the model is executed with stochastic optimization technology to yield an evaluation of risk-weighted selections for the decisions to be made (see Cullick et al [5]). Optimal scenarios are presented as a mean value versus risk (see Cullick et al [5]). Visualization begins with a structured framing of project components and potential characteristics, such as identifying formation candidates, formation volumes, formation integrity, and well count. Well types, well integrity and completions, monitoring, monitor assessment, and abandonment procedures are also evaluated. An IAM represents the physical system and its uncertainties, constraints, and concept alternatives. An optimization technology is used to evaluate many alternative scenarios and to rank those that best meet the objectives. The uncertainty ranges assigned to subsurface parameters that affect storability dictate the outcomes of the different decision options and overall scenarios simulated in the study for CO_2 injection and storage. Decisions investigated in this study for the aquifer are well count for injection, well location, and injection rates. For enhanced oil recovery sites, decisions include the field constraints, water-alternating CO_2 volumes, maximum Gas-Oil Ratio (GOR) of producer wells, and injection well selection. Other decisions, such as pipeline configuration and completion types, would normally be made in follow-up conceptualization and definition phases. The IAM uses a physics-based numerical simulator, which is described below. The IAM has a full-economic discounted cash-flow model that computes a net present value (NPV) for capital costs, operating costs, CO_2 injection credits, and for the EOR candidate revenue from oil production. The CO_2 injection credit was assumed to be $40 per ton.

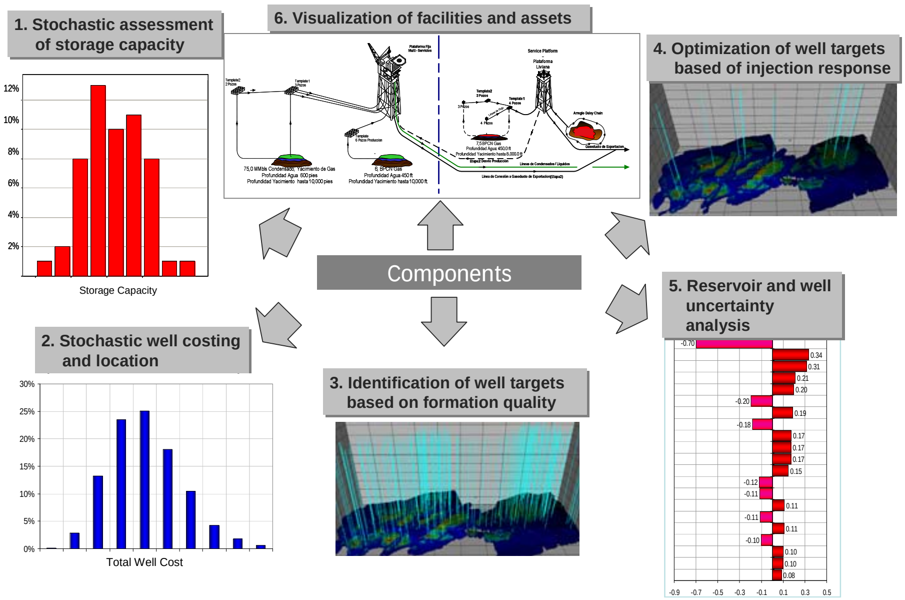


Figure 3 Components and workflow for the IAM.

Saline aquifer

Figure 4 illustrates the near saline aquifer formation. The subsurface model has uncertainty on total pore volume, compartmentalization, fault transmissibility, and the salinity. The estimates for volume range from about 3.2 billion surface m^3 of water to more than 8 billion surface m^3 with a mean of about 6 billion surface m^3. The uncertainty is related to gross volume, porosity, and net-to-gross uncertainties. The average depth is about 1520 m, and the initial pressure is about 160 bar at the top of the structure. The analysis is to determine the storability for the required plant effluent CO_2 volume and the number and location of wells required. A preliminary analysis is assumed to have identified thirteen well location candidates.

Enhanced oil recovery candidate

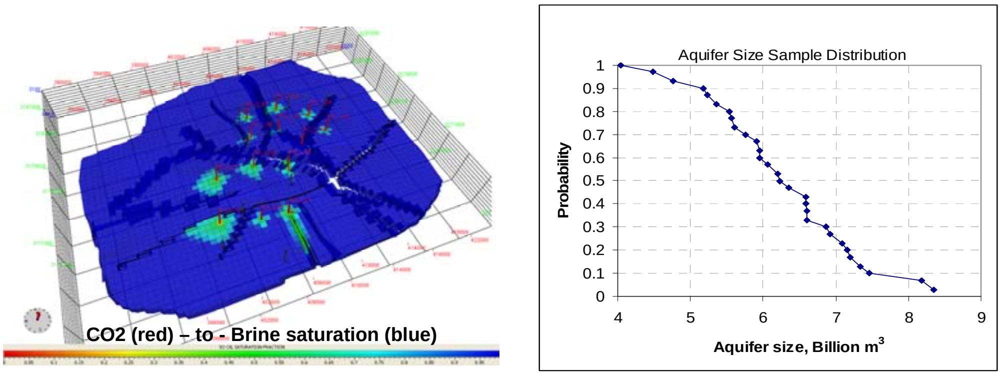
The enhanced oil recovery prospect has an original oil in place (OOIP) of 161 million reservoir m^3, 20 producers, and 10 injectors wells, and has been under a waterflood injection process for about 6 years. The reservoir is at a depth of 2,333 m, initial pressure of 228 bar and 118°C, and the fracture pressure is about 350 bar. The subsurface formation characteristics were taken from the Brugge study (Peters et al [6]). The formation temperature, pressure, and oil PVT mimic characteristics typical for waterflood candidates for a CO_2 miscible recovery process.

Figure 5 shows the structure of the model, the initial water saturation, the oil-water contact, and the location of producers and injectors.

The CO_2 was injected as a 1:1 ratio, Water-Alternating-Gas (WAG) process in every other injector switching the cycle every two years. The model was controlled by the BHP, not exceeding the fracture pressure as the fluids were injected. At the same time, different scenarios of maximum GOR for the producer wells were evaluated to shut in wells with GOR values too high. In these cases the wells were grouped into down-dip wells (lower in the structure closer to the injectors) and up-dip wells.

Numerical simulator for the IAM

The numerical reservoir simulator used in this work is a full-field, finite volume simulator and has been described by Coats et al. [7] and Shiralkar et al. [8].



Uncertainties:

- **Volume**
- **Transmissibility**
- **Compartmentalization**
- **Spatial distribution of salinity**
- **Capital costs**

Decisions:

- **Number of wells**
- **Location of wells**
- **Whether to develop versus distant, larger aquifer**

Figure 4 Near saline aquifer formation characteristics.

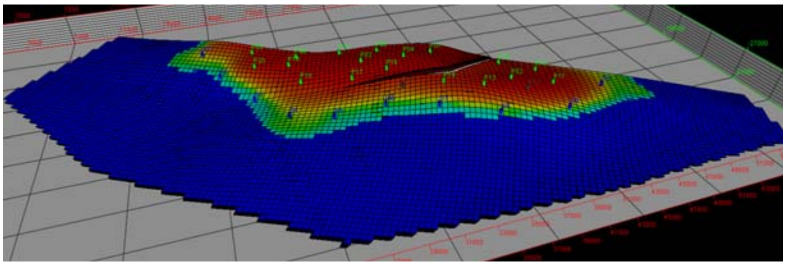


Figure 5 Subsurface model for CO_2 EOR for a waterflood oil project (Peters [6]).

The simulator has true multi-reservoir capability; it can couple multiple independent subsurface models, each with its own grid and fluid system, through a common network [9]. The CO_2 injection uses a Peng-Robinson equation of state (EOS) with a two-phase flash algorithm. The EOR candidate used an EOS for the CO_2-hydrocarbon phase behavior, with a tuned EOS. The simulator uses a table look-up procedure for CO_2 solubility in the aqueous phase in the presence of hydrocarbon. The saline aquifer candidate model used the EOS tuned for CO_2-brine phase behavior [10]. For the saline aquifer the injection is limited by the fracture pressure and an injection well bottom pressure constraint.

Results

The IAM was executed over the uncertainty ranges and the decision variables for the near saline aquifer and the onshore oil EOR candidates.

Saline aquifer candidate

Figure 6 presents a mean NPV versus its standard deviation and shows the best well number and location selection. The evaluation indicates that a well number of six or seven is best out of thirteen candidate wells, even with the best well selections. Figure 7 shows that the near aquifer has a risk to storability, which is the target 60 million tons of storage (30 billion m^3), and has a low probability of being met. Figure 8 illustrates through a correlation chart sensitivities of the NPV and CO_2 volume capacity related to formation parameters and other parameters. Fault transmissibility is a major factor. If the faults are not transmissive, the volume capacity is more limited. Predicted injection rates depend on the uncertainties and the decision selections. Figure 9 illustrates typical rates for a well taken over the uncertainty ranges for the best case (six wells, upper set of rates) compared with the case with all thirteen wells (lower set of rates).

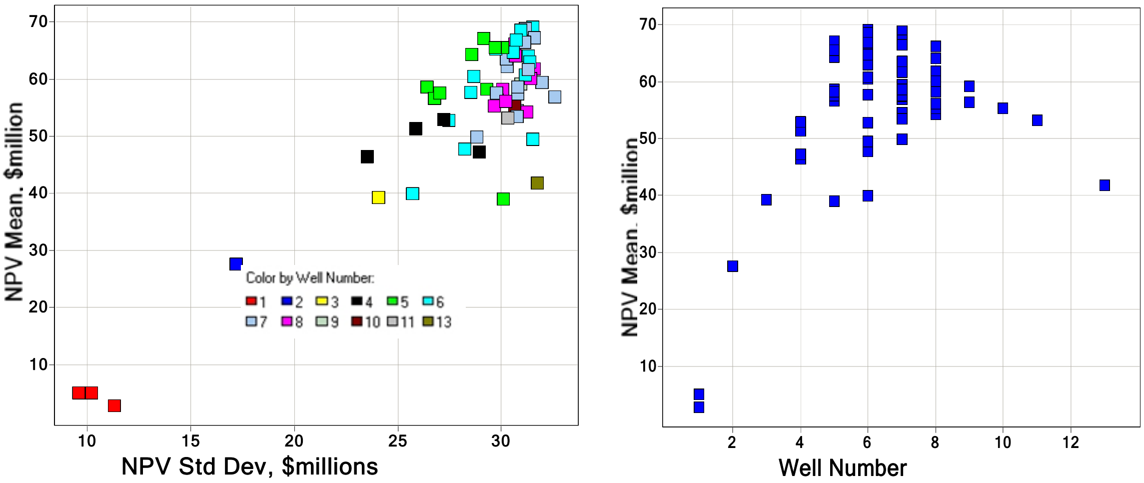


Figure 6 Optimal analysis for near saline aquifer.

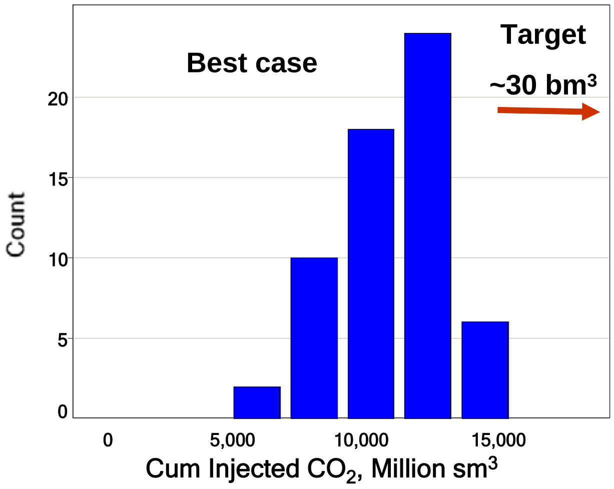


Figure 7 Best saline aquifer case expectations for storability.

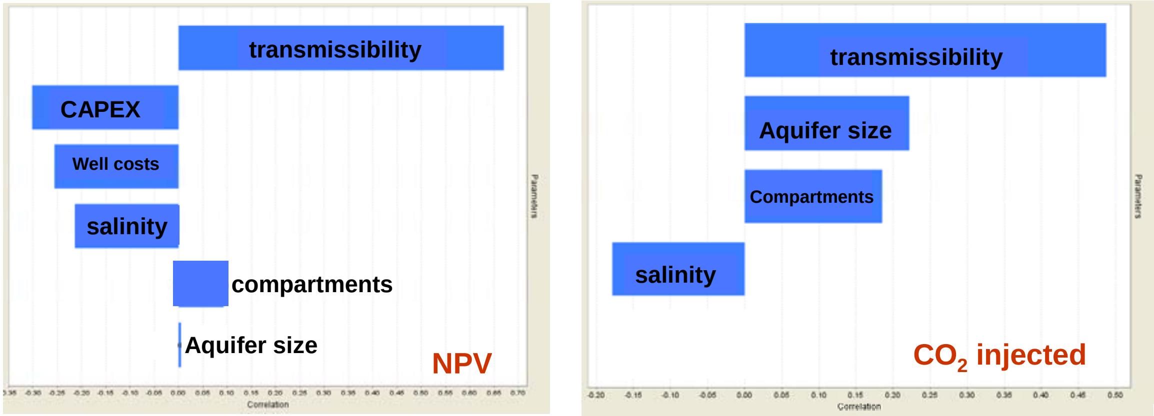


Figure 8 Sensitivity to uncertainties for the near saline aquifer.

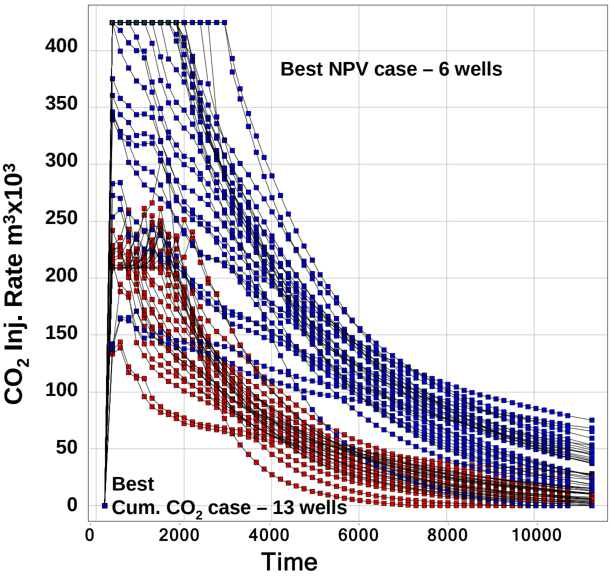


Figure 9 Different well numbers dictate injection rates.

Oil production EOR candidate

The plot to the left in Figure 10 shows the evaluation of the decision of what the optimum value of GOR should be to shut in the producer well. For example, the blue diamonds show a constant value for maximum GOR of down-dip wells as several values of up-dip wells GOR are evaluated; the effect can be observed in the incremental oil recovery. Changes in this variable represent relevant changes in the incremental oil. The probability of reaching the target CO_2 volume to be injected was also evaluated, taking into account the uncertainties in volume and sweep efficiency. The plot on the right side of Figure 10 shows the probability of reaching the total CO_2 target volume, taking into account the recycle volume of CO_2 during the EOR process. The mean value reached in the scenarios evaluated was close to 20 billion m^3 (or about 40 million tons), and the probability of reaching the total volume requirement (of 60 million tons) is only 5%. The IAM evaluates the impact of critical factors that affects the NPV of the project, including the decision of selling the CO_2 to the operator of the oil field or acquiring the field and operating it. Although a low probability of reaching the target CO_2 storage capacity was observed, the incremental oil recovery factor was approximately 40% of the OOIP for most of the scenarios evaluated. The analysis allows concluded, for example, that neither the highest NPV nor the highest net CO_2 injected are necessarily associated to the highest incremental oil.

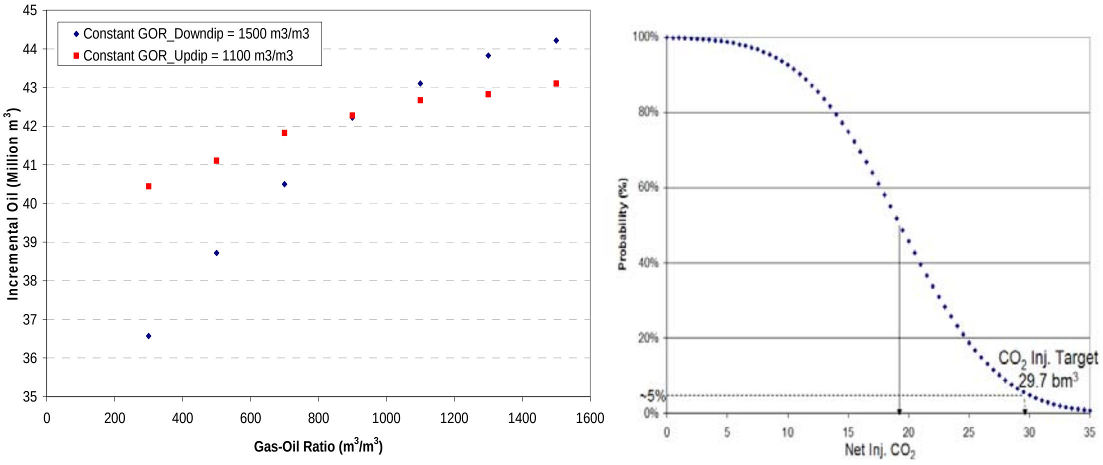


Figure 10 Operational sensitivity for decision variable GOR and probability of reaching the target CO_2 volume.

Discussion and Conclusions

The example illustrates the use of an IAM and stochastic optimization procedure for CCS evaluation. The IAM is executed over probability distributions of the uncertainties for a 550-MW power plant CO_2 emissions for 30 years. A probability distribution of storage capacity related to the uncertainties and the best number and location for injection wells are computed along with discounted cash-flow economics over a 30-year period. Storage capacity and injection rates are limited by the seal integrity fracture pressure. The example shows how sensitivity analysis and optimization can provide insight as to the best injection scenarios. Although not shown, an evaluation of the distant aquifer shows it to have sufficient capacity but at a high cost (negative NPV) because of pipeline cost.

The study also illustrated for this hypothetical example that no single storage site is estimated to have sufficient CO_2 capacity. The study process does indicate for each particular candidate its formation risks to ultimate storability at the formation fracture pressure. The case presented is an illustration of the proposed workflow. Scenarios for well types, locations, and pipeline configurations are investigated using an IAM. Deliverables are the best set of wells, facilities, and assessments for storage capacity and well integrity through long-term formation conditions.

In summary, for this hypothetical example, multiple storage sites with an optimized combination could potentially be the best solution to minimize costs and enable the storing of the target volume. The situation illustrated, although synthetic, may be typical of storage projects for which there is a requirement to evaluate many uncertainties and possible storage solutions for multiple candidate sites. A FEL approach enables rapid assessment of many alternatives and establishes overall uncertainty

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