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Impact of Underground Gas Storage in Depleted Reservoir on the Efficiency of Gas Supply in Nigeria

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Abstract

Breaches in gas sales and purchase agreements (GSPAs) due to gas supply shortages have seen gas companies unable to meet their domestic and foreign supply obligations. A gas storage facility in a depleted reservoir can potentially bridge the gas supply gap and eliminate such GSPA breaches. Therefore, this study aimed to investigate the impact of underground gas storage in a depleted reservoir on the efficiency of gas supply in Nigeria. The research methodology used several profitability indices to ascertain the feasibility of underground gas storage in depleted reservoir operations in the Nigerian gas market, using the Omoku gas power plant in Rivers State, Nigeria, as a hypothetical gas customer. Obtained results revealed that natural gas storage in Nigeria can be adjudged profitable. However, its profitability depends on several factors, such as average breach days per annum, discount rate, reservoir temperature and pressure, etc. For a projected project lifetime of 25 years, a total capital expenditure (CAPEX) of about $13,400,015.89 will be required to set up an underground depleted reservoir gas storage facility in the Niger Delta. Given an average annual cumulative breach day of up to 60 days, the net present value was found to be $1,644,477.3, with an internal rate of return and discounted payback period of 12.34% and 17.35 years, respectively, at a 10% discount rate. In addition, risk analyses done with Model Risk Monte Carlo simulation software further revealed average annual cumulative breach days as the variable with the highest influence on the economics of gas storage. Surprisingly, price-related parameters like gas price and breach penalty influenced only moderately the economics of natural gas storage.

Keywords: *Natural gas; Gas sales and purchase agreement; Underground gas storage; Depleted oil reservoir; Profitability indices.*

1. Introduction

By 2030, natural gas is expected to surpass coal as the fastest-growing fossil fuel and become the second energy source after oil. Natural gas accounted for 64% of the top 10 petroleum discoveries worldwide in 2018. The International Energy Agency [1] reports that strong economic development and the switch from coal-fired electric power to gas-fired electricity owing to climate change initiatives were among the factors driving the 4.6% increase in global demand for natural gas in 2018. China and the US led the global gas consumption trend, accounting for about half of the rise in energy demand. Nigeria contributed significantly to Africa's petroleum potential; in 2018, its share of global reserves was 29% and 21%, respectively [2].

The necessity to meet industrial emission requirements worldwide by switching from coal and oil to gas has resulted in the growth of petrochemical industries, which use gas as feedstock. This further demonstrated how the industrial sector's need for gas is expanding. For instance, in the electricity industry, efforts have been made to gradually replace coal and oil in the energy mix throughout important regions with gas and other renewable sources. Thus, gas-fired power plants and other renewables like solar and wind replace many coal-fired and nuclear-fired power plants. The International Maritime Organization (IMO) recently adopted a new policy in the transportation sector that caps the sulfur content at 0.5% utilizing bunker fuel, which is used in the maritime industry, has led to a hunt for substitute energy sources that abide by international regulations, such as low-sulfur diesel oil and liquefied natural gas (LNG). Another factor contributing to natural gas's growing popularity as an energy source is its efficiency and adaptability [2].

Nigerian gas is exported or utilized locally for power generation, industrial heating, fuel for natural-gas vehicles, and feedstock for gas-based industries, including fertilizer manufacturing and petrochemicals. Cooking and power generation also employ liquefied petroleum gas (LPG) from gas processing. The Nigerian National Petroleum Corporation (NNPC) claims that the country's increased gas consumption came from power sector reforms and prioritizing gas-powered generating facilities. Furthermore, the paradigm for cooking has shifted from kerosene stoves and firewood to LPG due to government-led changes.

Between 2001 and 2017, the Nigeria Liquefied Natural Gas (NLNG) Company could export more than 13 TCF of LNG. At that time, they held an equal share of approximately 7% of the world's natural gas exports [2]. According to PwC, Nigeria's proven gas reserves can boost the country's economy by an estimated US$18.3 billion a year in gross value added (GVA). Optimizing the use of gas domestically might also sustain an additional 6.5 million Full Time Equivalent (FTE) employment for the local economy. According to official data, Nigeria may save more than N10 trillion annually if all of the cars in Lagos, Port Harcourt, and Abuja switched to compressed natural gas (CNG) instead of regular petroleum products [2].

There is a significant disparity in gas availability and supply consistency for off-takers, even with these potentials. These supply shortfalls have generally led to violations of gas sales and purchase agreements (GSPAs), making the suppliers liable. Liabilities of this type account for extra expenses borne by the gas suppliers, undermining profitability. Gas firms such as the NLNG and multinational oil and gas enterprises have been unable to fulfil their domestic and foreign supply obligations due to GSPA breaches caused by shortages in gas supplies. To stop these GSPA breaches, a gas storage facility can assist in filling the gap in the gas supply. Additionally, the non-linear autoregressive exogenous neural network (NARX) model has been identified as an effective tool for predicting Nigeria's average natural gas demand [3].

This study conducted an economic evaluation of the feasibility of incorporating natural gas storage in the Nigerian gas market. It was carried out as a possible panacea for the incessant gas sales and purchase agreements (GSPAs) bedeviling the Nigerian gas market, which has caused gas companies to be unable to fulfil their gas supply obligations. From the literature review, this study represents the first attempt at such studies for the Nigerian gas market. In addition, an accompanying economic model was equally created as part of this study. This presents a veritable tool for potential use by policymakers responsible for making high-level co-corporate decisions regarding setting up natural gas storage facilities. The economic model allows various economic scenarios to be easily evaluated on merit, guaranteeing reliable choices.

2. Methodology

The research methodology entails an economic evaluation of gas-storage operations in the Nigerian gas market. This would be done using several profitability indices to ascertain the feasibility of undertaking gas-storage operations. The gas-storage type of choice would naturally be a depleted reservoir. The reason for using a depleted reservoir is that there are no known salt deposits in the Niger Delta to consider gas storage in salt caverns. Although there are salt springs at Awe in Plateau State, Abakaliki, and Uburu in Ebonyi State, rock salt (suitable for gas storage) is also available in Benue State [4].

Aquifer gas storage was also not selected due to the high costs of reconditioning for gas storage and the duration for development before aquifer gas storage facilities come on stream.

In addition, there are substantial environmental concerns surrounding the development of aquifer gas-storage facilities in that it can cause contamination of aquifers as sources of drinking water. In the second stage, an incremental cost/benefit analysis would compare the cost and benefits of setting up gas-storage facilities against incurring costs of gas sales and purchase agreement breaches.

For this study, a depleted oil reservoir would be used for analysis since depleted oil reservoirs are common in the Niger Delta. In this study, a depleted oil reservoir is taken as a reservoir that has been depleted to its economic limit, such that no feasible enhanced oil recovery methods can guarantee further production. The designated oil reservoir is also assumed to belong to an oil-producing company with significant contractual gas obligations. The oil producer is considered large enough to operate multiple reservoirs, from which a previously depleted reservoir is selected for gas storage without incurring additional charges in storage space rents. The schematics of gas underground storage in the depleted reservoir process are shown in Figure 1.

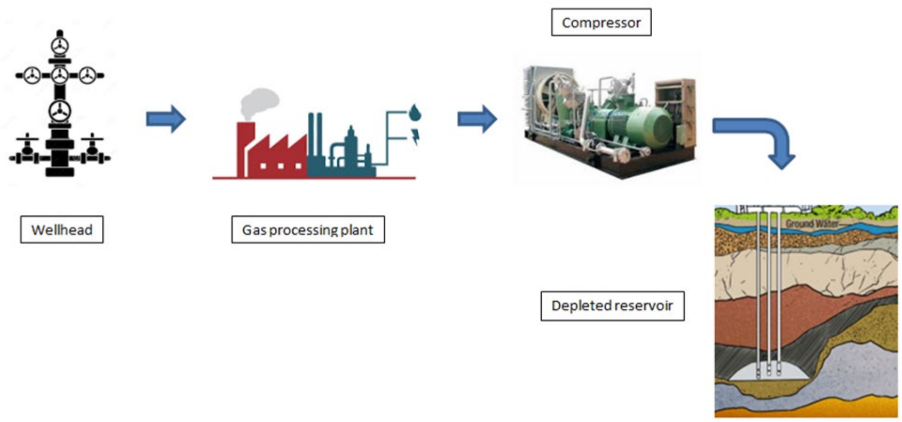

Figure 1. Schematics of the natural gas underground storage process.

2.1. Description of profitability indices

2.1.1.Net present value (NPV)

NPV represents the remainder of initial investments after subtracting the present value of all cash inflows and outflows from the future. NPV is calculated from:

$$NPV = \sum_{i=1}^{n} \frac{NCF_i}{(1+r)^t} - C_o \quad (1)$$

where C_0 equals initial investment; NCF_i, respective period net cash flows; r discount rate, and t equals end period [5].

2.1.2. Internal rate of return (IRR)

IRR represents the highest allowable rate of return on initial investments for a given business. Mathematically, it is the discount rate that makes NPV zero. IRR is calculated from the following formula.

$$\sum_{i=1}^{n} \frac{NCF_i}{(1+IRR)^t} = 0 \quad (2)$$

where NCF_i is the respective period's net cash flows; IRR is the internal rate of return; and "t" is the end period [5].

2.1.3. Discounted payback period

It calculates the duration in years it will take an investment to break even while considering the time value of money. It is represented mathematically below [5].

$$Payback\ period = Cum - ve\ NCF + \frac{1}{+ve\ NCF - (-ve\ NCF)} X - (-ve\ NCF) \qquad (3)$$

where *Cum-ve NCF* is the cumulative year with a negative NCF; while *+ve* and *–ve* NCF are the first positive and last negative net cash flow, respectively.

2.1.4. Minimum bill quantity

This quantity of gas is what the gas buyer is obligatorily mandated to either pay for or take under contract. The amount specified is frequently set to between 70 to 90 % of the annual contract quantity with minor adjustments. Possible reasons for adjustments include the inability of the seller to supply contractual amounts, the quantity of gas the buyer could not accept due to unintended outcomes beyond the buyer (for instance, scheduled maintenance) or previously unrealized purchases. Mathematically, minimum bill quantity is expressed as:

$$\text{Minimum Bill Quantity} = (\%\ \text{Take or Pay})\ \text{X}\ (\text{Adjusted Annual Contract Quantity}) \qquad (4)$$

where adjusted annual contract quantity is given by:

$$\text{Adjusted Annual Contract Quantity} = \text{Annual Contract Quantity} - \text{Shortfall Gas from Seller} - \text{Gas Quantity Unfulfilled Due to } \textit{Force Majeure} - \text{Cumulative Carry Forward Gas} \qquad (5)$$

2.2. Economics of depleted reservoir gas-storage in Nigeria

For the evaluation of the feasibility of gas underground storage in Nigeria, a depleted oil field in Niger Delta was selected. The selected field was chosen since it has sufficiently been exploited to guarantee a significant potential storage volume for gas, as depicted in Table 1.

Table 1. Reservoir parameters for depleted oil field A (case study) in the Niger Delta Source.

Parameter	Unit	Initial value	Current value
Porosity	%	30	15
Permeability	MD	1931	1014
Thickness	ft	24	17.8
Initial water saturation	%	21	18
Hydrocarbon saturation	%	79	7.5
Reservoir pressure	psia	5512	568
Net-to-gross ratio	(-)	0.83	0.15
STOIP	MMbbl	26.3	-
Cumulative oil produced	MMbbl	-	12.5
Well depth	ft	11,668	11,665
Reservoir temperature	oF	198	121
Abandonment well pressure	psia	-	50

The hypothetical customer to the gas seller is the Omoku gas power plant in Rivers State, South-South, Nigeria. The average operating data for the gas power plant (also located in the Niger Delta) is presented in Table 2. This includes data for the combustion chamber, turbo compressor, gas turbine and other relevant data.

The cumulative stock tank oil produced was converted to reservoir volume using the oil volume formation factor to ascertain the reservoir volume available for underground gas storage. Values for the oil volume formation factor typically vary from about 1 bbl/STB for oil with minimal solution gas to about 3 bbl/STB for highly volatile oils, so a value of 2 bbl/STB was assumed. Using any available correlations for oil volume formation factors like the Standing or Petrosky correlation would have proved problematic since the oil ratio was not given.

The reservoir volume occupied by the cumulative stock tank oil produced was then equated with the reservoir volume occupied by stored natural gas. The gas formation volume factor was calculated to get the surface volume of stored gas. The surface volume was later calculated in cft and converted into the heating value (Btu) and pound mass (lbm) equivalents for upcoming calculations. After that, the total surface gas volume is divided into 50% cushion gas and the balance working gas. The cushion gas is usually left in the storage facility to guarantee the gas withdrawal of sufficient pressure. The choice of 50% cushion gas agrees with both Chen *et al.* [7] and Lord *et al.* [8], who stated that 50% cushion gas is usually required in depleted underground gas storage facilities.

Table 2. Average operating data for Omoku gas plant in Rivers State, South-South Nigeria [6].

Component	Parameter	Unit	Value
Turbo compressor	Inlet pressure	bar	1.013
	Outlet temperature	°C	367
	Outlet pressure	bar	10
	Inlet temperature	°C	30.4
Combustion chamber	Mass flow rate (Air)	kg/s	122.9
	Inlet temperature	°C	959
	Fuel consumption (flow rate)	kg/s	1.2
	Exhaust gas flow rate	kg/s	124.1
	Outlet temperature	°C	487
Other data	GT power output	MW	25
	GT thermal efficiency	%	26.6

The gas power plant feed gas rate of 1.2kg/s was first converted into its pound mass equivalent and later converted into the gas volume at standard conditions using the real-gas equation of state (EoS). For the real-gas EoS, the gas compressibility factor was calculated using the California Natural Gas Association (CNGA) correlation. From the resulting gas volume, the daily contract quantity (which is the daily minimum bill quantity here) was calculated in both cubic feet per day (cfd) and heating value (Btu). A gas price of $2/MMBtu was adopted as the most recent gas price suggests, while a gas sales and purchase agreement (GSPA) breach penalty of $3.5/MMBtu was equally adopted. The penalty was chosen in agreement with the recently passed Petroleum Industry Act (2022), which stipulates daily domestic gas obligations for all gas producers.

The new act also stipulated $3.5/MMBtu as the breach penalty except for a subsisting gas sales and purchase agreement (GSPA). For the act, they also specified that the penalties contained in such contracts cannot be lower than $3.5/MMBtu. Meanwhile, the domestic gas obligation can also be taken as a form of gas sales and purchase agreement (GSPA) between the government and the gas producers with its breach penalty. This penalty price is appropriate since paying a penalty higher than the base gas price will serve as a valuable deterrent for GPSA breaches.

The overnight cost of the compressor for the underground storage facility was obtained from Chen *et al.* [7] as $10,189,467, while the compressor capacity of 10,000 kg/hr was selected to ensure compression and storage of gas could be done within a year. For the gas storage capacity of the oil reservoir chosen, the available underground storage space could be filled in 252.25 days of compression. The total capital expenditure now includes the compressor's overnight cost, the cushion gas cost, and the operating expense for running the compressor on storage days. A discount rate of 10% was chosen in agreement with similar studies [9]. An average number of breach days per year variable was introduced to capture the number of breaches per year. This was done due to the inability to predict the number of violations in a given financial year. However, having an average value spread across each operational year can allow meaningful economic evaluation to be carried out without compromising accuracy. Care was also taken to ensure that the average number of breach days per year values were, at most, the maximum number of days the stored gas would usually last, given the calculated minimum bill quantity. This way, the potential variation in the number of breach days in a year can effectively be represented as an average over the whole financial period of consideration (project lifetime). The financial outlay of the economic model is presented in Appendix A.

Cash flows were later determined for both the incurred costs due to GSPA breaches and capital and running costs of underground gas storage facilities for 25 years using the simple Excel method of cash flow determination. This duration was chosen since project cash flows of more than twenty-five years do not significantly impact the project economics due to the effects of the time value of money [5]. Revenues were the total gas sales amount usually lost with a storage facility, and a breach penalty was avoided for each potential breach day. The revenues were used to compensate for the total capital expenditure calculated above. Several simulated scenarios were later investigated using important parameters like gas price, penalty price, cushion gas percentage, etc.

Furthermore, profitability indicators like NPV, IRR, and payback time were also used to determine underground gas-storage facilities' economic feasibility and impact on supply obligations. In addition, risk analysis using ModelRisk Monte Carlo software was used to determine the associated risks.

3. Results and discussion

The study results are presented below following the order in which they were generated. This includes the profitability and risk analysis results of underground gas storage in Nigeria. The profitability analysis results include net present values at various discount rates and average breach days per year. From where the internal rates of return for each average breach day scenario were also calculated. Next, the corresponding discounted payback periods for each combination of discount rate and average breach day per year variables were equally calculated. Finally, ModelRisk Monte Carlo simulation software was utilized for the ensuing risk analysis.

Figure 2 shows a net present value (NPV) plot at various discount rates for different average breach days per annum. At first glance, it can be seen that for each plot, an inverse proportionality can be noticed between net present value and discount rate. This shows that increasing the discount reduces the net present value derivable from setting up an underground natural gas storage facility. The discount rate represents the weighted cost of capital for a given project, which is the cost of acquisition of capital for a selected project. This explains why, for the rising cost of capital (which signifies a rising discount rate), the net present value of all future cash flow derivable from the project will correspondingly decrease. This is usually the case considering the effect of the time value of money on project economics [9].

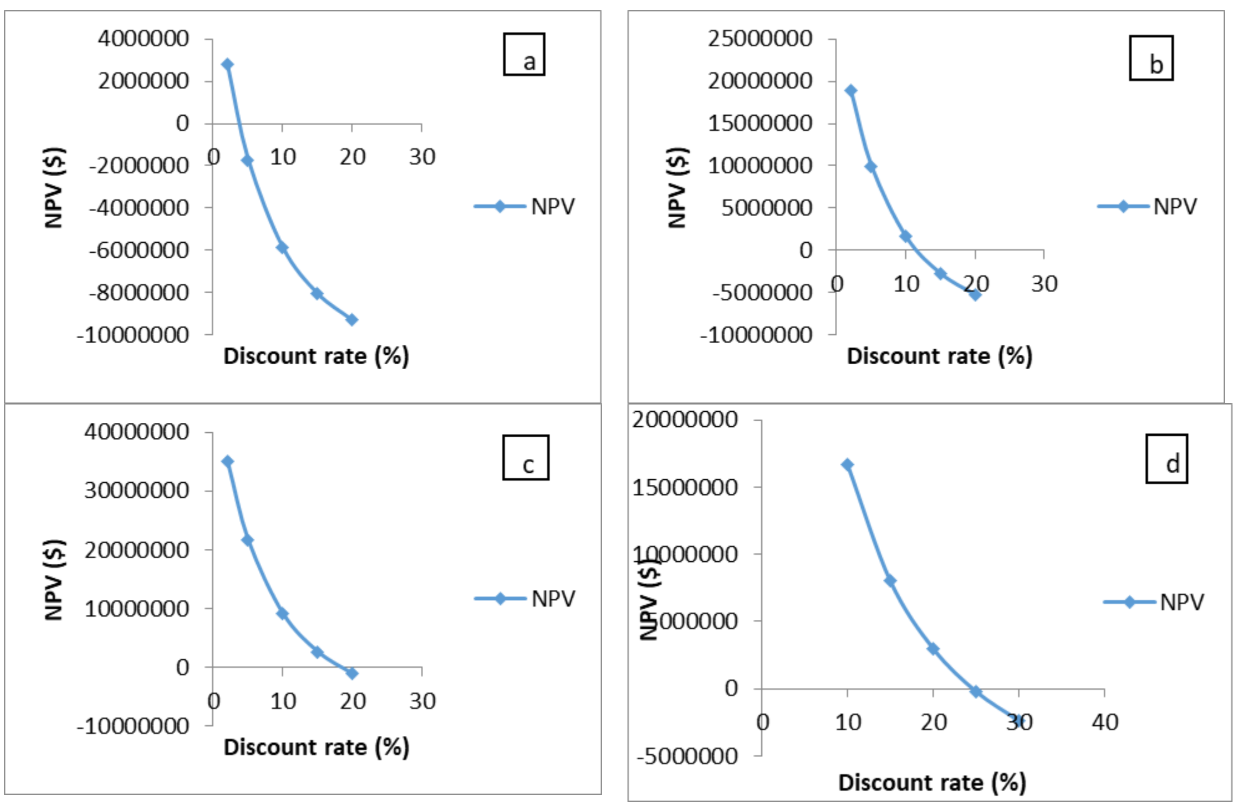

Figure 2. Plot of net present value (NPV) at various discount rates for different average breach days per annum (a) 30 days (b) 60 days (c) 90 days (d) 120 days.

Figure 2 also reveals that each net present value (NPV) curve bestrides the horizontal axis for each average breach day per annum selected. This divided the NPV curve into regions of negative and positive net present values recorded at different discount rates. The discount rates that recorded positive net present values represent those that can provide net positive value or returns. On the other hand, the discount rates that give negative net present values will give net negative value or returns. This usually guides decision-makers when using net present value as a criterion for deciding whether to proceed with a given project. The figure shows that when the average breach days are only about 30 days, underground natural gas storage can only become valuable at discount rates much lower than 5%. This explains why the net present value was positive at a discount rate of 2%. However, when the average breach days are about 60, underground natural gas storage remains valuable at up to a 10% discount rate. At discount rates higher than that, underground natural gas storage would be uneconomic to set up. In addition, when the average breach days are up to 90 days, underground natural gas storage can only become unattractive from discount rates of 20% and above. When the average annual duration of a breach in gas sales and purchase contracts lasts 120 days, underground natural gas storage becomes unprofitable at discount rates of 25% and higher.

Table 3. Internal rate of return at various average breach days per annum.

Average breach days per annum (days)	Internal rate of return (%)
30	3.61
60	12.37973
90	18.70834
120	24.94023

Table 3 shows the internal rate of return at various average breach days per annum. The internal rate of return is usually calculated as the discount rate that makes the net present value for a given project zero. It also signifies the discount rate above which a given project becomes valuable and below which the project turns unprofitable. Projects with favourable internal rates of return are usually acceptable as a project decision criterion, while those with negative internal rates of return are discarded. However, when the decision maker faces multiple projects to choose from with limited available resources, the project with the highest is usually chosen from among equally likely options.

Table 3 shows that for average breach days of 30 and 60, the internal rates of return were 3.61% and 12.38%, respectively. While for average breach days of 90 and 120, the internal rates of return were 18.71% and 24.92% respectively. This shows that underground natural gas storage is profitable, as depicted by the all-positive internal rates of return at different average breach days per annum. However, the internal rates of return also exhibited direct proportionality with the average breach days per annum variable. The internal rates of return were increasing as the average breach days per annum increased. This observation shows that natural gas storage is more profitable as the days of gas sale and purchase contract breaches become longer. This is expected since gas storage facilities are the only valuable backup options when expected gas delivery is disrupted. In addition, the above observation further signifies the considerable effect the duration of the breach has on the feasibility of natural gas storage. Consequently, for highly efficient gas producers with a low likelihood of gas sales and purchase agreement breaches (with average breach days of 30 days and less), the low profitability indices of natural gas storage might need to be more attractive. However, for inefficient gas producers with a high likelihood of gas sales and purchase agreement breaches (with average breach days of 60 days and above), the high profitability indices of natural gas storage might prove a game changer regarding potentially realizable returns.

Here, breach days are used in the strictest possible sense to include even *force majeure* situations like scheduled maintenance. Although the gas producer does not pay penalties in these situations, revenue is always lost on any sales that are not made. Such revenues are recovered but deferred to futuristic time frames. Considering the time value of money, revenues deferred do not always have the same present values. For a capital-intensive industry like the oil and gas industry, deferred revenues due to production disruptions are usually frowned upon. This further highlights the potential value derivable from natural gas storage as it can sustain revenue streams even in *force majeure* situations.

Table 4 shows discounted payback periods at various discount rates for average breach days per annum. The discounted payback period estimates the cumulative discounted cash flow's duration to zero. It is usually preferred since it incorporates the effect of the time value of money compared to the undiscounted payback period. For average breach days of 30, it can be observed from Table 4 that the discounted payback period was given for only the discount rate of 2%. This was because, at higher discount rates, the discounted payback period was indeterminate as the cumulative discounted cash flow failed to turn positive within the projected lifetime of the gas storage project (30 years). Interestingly, the discounted payback period recorded at a discount rate of 2% is 19.73 years, which is too long to make gas storage attractive. This result further confirms the result of Figure 2a for average breach days of 30, in which the NPV was negative at all selected discount rates apart from 2%.

Furthermore, the remaining average breach days showed increasingly lower discounted payback periods. For average breach days of 60, the discounted payback period ranged from 8.91 years at a 2% discount rate to 17.35 years at a 10% discount rate. Also, for average breach days of 90, the discounted payback period ranged from 5.76 years at a 2% discount rate to 11.84 years at a 15% discount rate. The lowest discounted payback periods were recorded for the average breach days of 120 days. For 120-day annual average breaches, discounted payback periods ranged from 4.26 years at a 2% discount rate to 9.07 years at a 20% discount rate. This further confirms the influence of the average breach days per annum on the economics of natural gas storage.

Table 4. Discounted payback periods at various discount rates for different average breach days per annum.

Average breach days per annum (days)	Discount rate (%)	Payback period (yrs)
30	2	19.7
	5	-
	10	-
	15	-
	20	-
60	2	8.9
	5	10.6
	10	17.3
	15	-
	20	-
90	2	5.8
	5	6.4
	10	8.1
	15	11.8
	20	-
120	2	4.2
	5	4.6
	10	5.4
	15	5.7
	20	9.1
	25	-
	30	-

In addition, it can also be deduced that for a given average breach days value, there was an inverse relationship between the discounted payback period and the discount rate as the calculated discounted payback periods were increasing as the discount rates increased. This observation can be explained by the fact that at higher discount rates, the present value of future cash flows is usually low compared to lower discount rates. This prolongs the duration for future revenues to balance the usually front-loaded significant capital expenses every project requires. Similarly, the discounted payback period was indeterminate at the highest discount rates as the cumulative discounted cash flow failed to turn positive within the projected lifetime of the gas storage project (30 years).

Figure 3 shows the Tornado chart, which shows the influence of various parameters on the net present value (NPV). The parameters captured in the Tornado chart are independent parameters whose values were not dependent on any other parameter. As expected, the average breach days are undoubtedly the parameter with the highest impact on the economics of natural gas storage. This result coincidentally agrees with the previously discussed results outlined above. Reservoir temperature is the parameter with the subsequent highest impact on underground natural gas storage economics. According to Charles's law, this is deservedly so because the gas volume is proportional to temperature. The higher the reservoir temperature, the more gas can be stored.

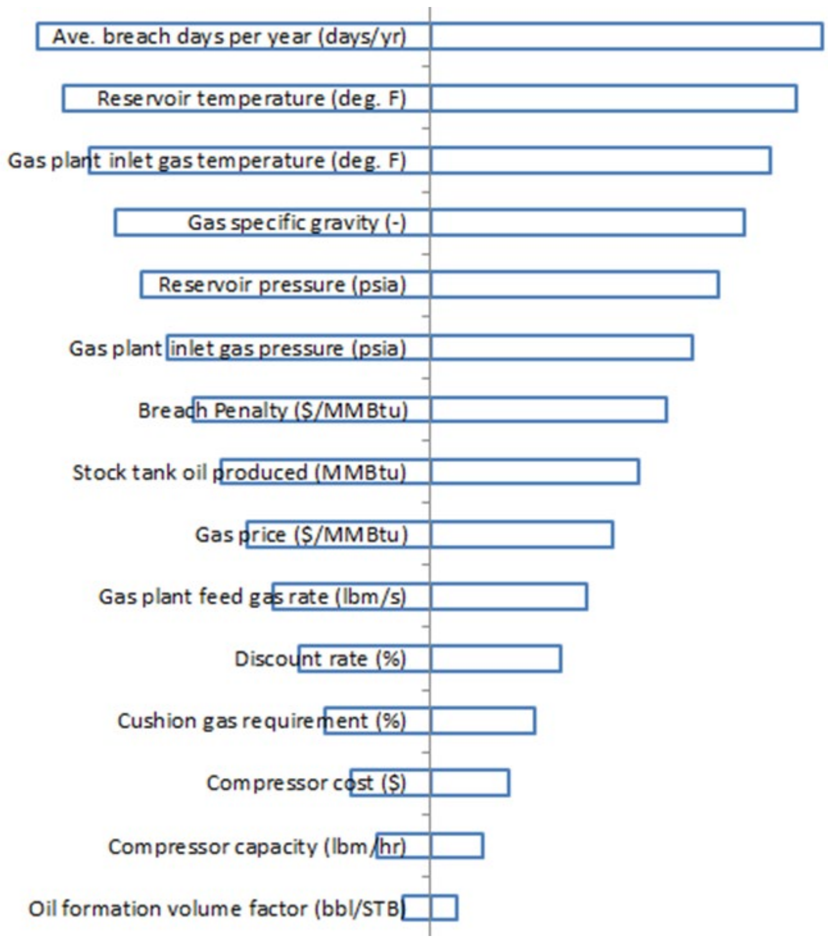

Figure 3. Tornado chart showing the influence of various parameters on the Net Present Value (NPV).

The same principle explains why gas power plant feed gas inlet temperature equally ranks high in terms of influence of the net present value. The gas temperature determines how much volume is withdrawn from underground storage, ultimately affecting revenue. The following important parameter is the gas-specific gravity, which influences how much gas mass is contained in each volume of gas withdrawn. The reservoir pressure also ranks high among the parameters affecting underground natural gas storage economics. According to Boyle's law, this is because of the indirect relationship between gas pressure and volume.

Surprisingly, price-related parameters like gas price and breach penalty influenced only moderately the economics of natural gas storage. The breach penalty was more critical to natural gas storage economics than gas price. This may be connected to thermodynamic variables like temperature and pressure being far more critical for gaseous matter than natural gas. On the other hand, the five (5) least essential parameters were found to be (in that order) discount rate, cushion gas requirement, compressor cost, compressor capacity and oil volume formation factor.

4. Conclusion

Natural gas storage in Nigeria can be adjudged profitable. However, its profitability depends on several factors, such as average breach days per annum, discount rate, reservoir temperature and pressure, etc. For instance, increasing the discount reduces the net present value derivable from setting up an underground natural gas storage facility. The average breach days per annum were found to wield an overwhelming influence on the profitability of natural gas storage. Higher net present values, internal rate of return, and discounted payback periods were recorded for longer average breach days per annum.

For highly efficient gas producers with a low likelihood of gas sales and purchase agreement breaches (with average breach days of 60 days or less), the low profitability indices of natural gas storage might prove unattractive. However, for inefficient gas producers with a high likelihood of gas sales and purchase agreement breaches (with average breach days of 90 days and above), the high profitability indices of natural gas storage might prove a game changer regarding potentially realizable returns. Surprisingly, price-related parameters like gas price and breach penalty influenced only moderately the economics of natural gas storage. The breach penalty was adjudged as being more critical to the economics of natural gas storage than gas price.

Appendix A. Economics of depleted reservoir gas storage in Nigeria

Parameter	Unit	Value
Stock tank oil produced (N_p)	MMSTB	12.5
Oil formation volume factor (Bo)	bbl/STB	2
Depleted oil reservoir volume (V_{or})	bbl	6250000
Gas equivalent of depleted reservoir volume (V_{gr})	bbl	6250000
Reservoir temperature (T_r)	^oF	198
Reservoir temperature (T_r)	^oR	658
Gas specific gravity (s_g)	(-)	0.65
Reservoir pressure (P_r)	psia	5512
Gas compressibility factor (z)	(-)	0.688112054
Gas formation volume factor (B_g)	cft/Scf	0.002324675
Standard volume of storage gas (V_{gs})	cft	2688547610
Standard volume of storage gas (V_{gs})	But	2.78802E+12
Standard volume of storage gas (V_{gms})	LBM	133494204.9
Gas power plant feed gas rate (F_g)	kg/s	1.2
Gas power plant feed gas rate (F_g)	lbm/s	2.646
Gas power plant inlet pressure (P_{in})	bar	1.013
Gas power plant inlet pressure (P_{in})	psia	14.692552
Gas power plant inlet temperature (T_{in})	^oC	30.4
Gas power plant inlet temperature (T_{in})	^oF	86.72
Gas power plant inlet temperature (T_{in})	^oR	546.72
Universal gas constant (R)	psia.ft/lb-mol^oR	10.732

Parameter	Unit	Value
Gas volumetric feed rate (F_g)	cft/s	56.05661566
Daily contract quantity (DCQ)	cfd	4843291.593
Daily contract quantity (DCQ)	Btu/d	5022493382
Daily contract quantity (DCQ)	MMBtu/d	5022.493382
Gas price	$/MMBtu	4
Breach penalty	$/MMBtu	3.5
Cushion gas requirement	%	50
Working gas requirement	%	50
Cushion gas	MMBtu	1394011.936
Working gas	MMBtu	1394011.936
Compressor cost	$	10189467
Operating expenditure (OPEX)	$/day	1674.980877
Capital expenditure (CAPEX)	$	15765514.74
Average breach days per year	days/yr	60
Compressor capacity	kg/hr	10000
Compressor capacity	LBM/day	529200
Compression days	days	252.2566231
Total operating expenditure	$	422525.0197
Total capital expenditure	$	16188039.76
Discount rate	%	10
Maximum gas withdrawal days	days	277.5537625

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