

Article

Directional Hydraulic Characteristics of Reservoir Rocks for CO₂ Geological Storage in the Pohang Basin, Southeast Korea

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Abstract: This study conducted core sampling of an offshore borehole for geological reservoir characterization of a potential CO₂ storage site in southeast Korea. From this, two promising geological formations at ~739 and ~779 m were identified as prospective CO₂ storage reservoirs. Injection efficiency and CO₂ migration were evaluated based on directional measurements of permeabilities from core plugs. The directional transport properties were determined using both a portable probe permeameter and a pressure cell capable of applying different in situ confining pressures. Both steady state and unsteady state measurements were used to determine permeability—the method selected according to the expected permeability range of the specific sample. This expected range was based on rapid screening measurements acquired using a portable probe permeameter (PPP). Anticipated performance of the prototypical CO₂ injection site was evaluated based on flow modeling of the CO₂ plume migration pathway including CO₂ transport through the overlying formations based on the measured directional hydraulic properties. These analyses revealed that the injection efficiency at a depth of 739 m was double that at 779 m. These correlations among and distributions of the directional permeabilities of the potential CO₂ geological storage site can be utilized for the assessment of CO₂ storage capacity, injectivity, and leakage risk.

Keywords: carbon capture and storage (CCS); CO₂ geological storage; permeability; directional permeability

1. Introduction

Carbon capture and storage (CCS) in underground geological formations can reduce atmospheric carbon dioxide (CO₂) levels, thereby combatting climate change and minimizing the effect of industrial CO₂ emissions [1]. Specifically, CO₂ geological storage is recognized as one of the most effective CO₂ reduction methods as it offers significant storage capacity and high efficiency in field applications [2]. Deep geological CO₂ storage sites are considered most promising, but these sites are associated with uncertainties regarding storage security and the risk of leakage into the atmosphere [3]. Deeper reservoirs with overlying cap rocks and sufficient porosity for large storage volumes are considered suitable geological formations for CO₂ storage. Furthermore, these sites should offer significant storage capacity with adequate injectivity, where injection at high flow rates and without excessive pressure build-up results, where sufficient permeability exists [4]. Therefore, detailed geological characterization of the porosity and permeability of a potential CO₂ storage reservoir must be conducted to determine the storage capacity

and injectivity. In addition, the directional permeability of a storage reservoir determines its injected CO₂ migration behavior and leakage risk [5,6], where only one directional permeability is typically measured or estimated when assessing the horizontal or vertical mobility of injected CO₂. Furthermore, most previous studies have only considered horizontal permeability when assessing injection efficiency, CO₂ flow, and leak [7–10].

This study characterizes CO₂ storage in reservoirs based on the measurement of directional hydraulic properties to overcome the limitations of past research measurements using a newly development system. A potential CO₂ geological storage site in the Pohang Basin, southeast Korea was selected based on offshore seismic exploration [11,12]. Rock samples were cored through the full depth of the reservoir from a single offshore borehole to determine the directional hydraulic properties based on measurements using a portable probe permeameter (PPP) and a broadband rock permeability measurement system developed in this study. These experimental findings were used to develop a numerical model for injected CO₂ plume migration.

2. Field Site

Core rock samples were recovered from an offshore borehole (PHOD-1 well) in the Pohang Basin, southeast Korea (Figure 1). This site was considered as a potential offshore CO₂ geological storage site based on injection and storage testing, as well as monitoring of secured and stored CO₂ within its deep geological formations. The sedimentology and heterogeneous geological formations of the Pohang basin have been extensively investigated [13–15]. The Pohang Basin was considered because it comprises gravelly sandstone and conglomerate that either lie above or adjacent to pre-Miocene volcanic rock—and therefore represent highly permeable reservoir rocks with competent caprocks. The reservoir in Pohang basin was shown flat bedding by 3D seismic and the stratigraphic [16–18]. Core logging data were recovered from an offshore 1000 m borehole (PHOD-1 well). Geological interpretation of the stratigraphic section between 720 m and 795 m revealed that the formation below 735 m primarily consisted of sandstone and conglomerate with overlying thick mudstone above 735 m (Figure 1). Thus, this selected section was hydraulically confined by the overlying impermeable formation.

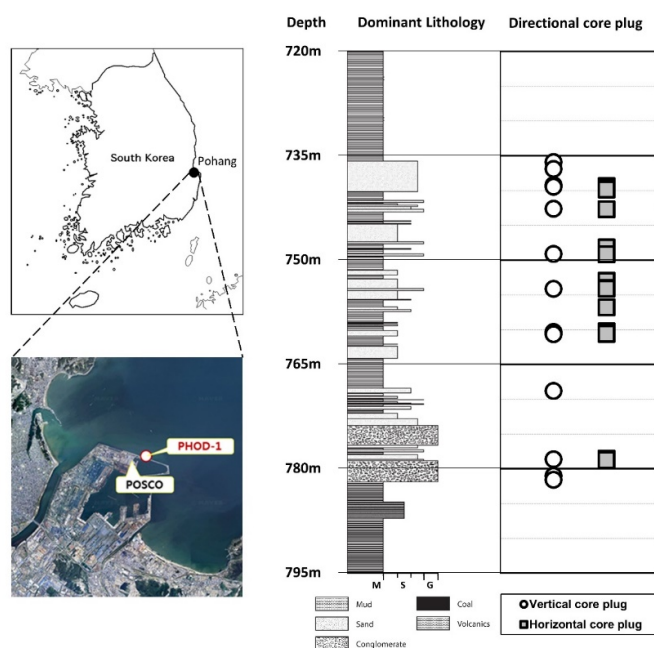


Figure 1. Geological stratigraphic section with sampling locations from the Pohang basin, offshore Southeast Korea.

3. Directional Core Preparation

Core sampling was conducted for the estimation of hydraulic properties, and was specifically performed for samples of the permeable rock. Both vertical and horizontal core plugs were prepared. Cylindrical cores (diameter = 58 mm) were recovered via wireline drilling with a core barrel from the single offshore borehole at the potential CO₂ geological storage site. However, conventional 58 mm diameter cores provide a limited indication of directional hydraulic properties due to the absence of a sidewall coring technique. Thus, directional core preparation was conducted with saturated density measured using the directionally cored plug samples. Mini core plugs (diameter = 25.4 mm) were subsampled vertically (i.e., perpendicular to the core bedding direction) and horizontally (i.e., parallel to core bedding direction) to characterize the anisotropic hydraulic properties using a high-precision core preparation mill (Figure 2). A total of 32 mini core plugs (14 vertical and 18 horizontal) were recovered to minimize damage due to the high-density drilling mud, and were used to analyze the directional hydraulic properties, including porosity and permeability (Table A1). These directional hydraulic properties provided valuable insights into the anticipated long-term CO₂ plume migration and trapping properties of the potential CO₂ geological storage site.

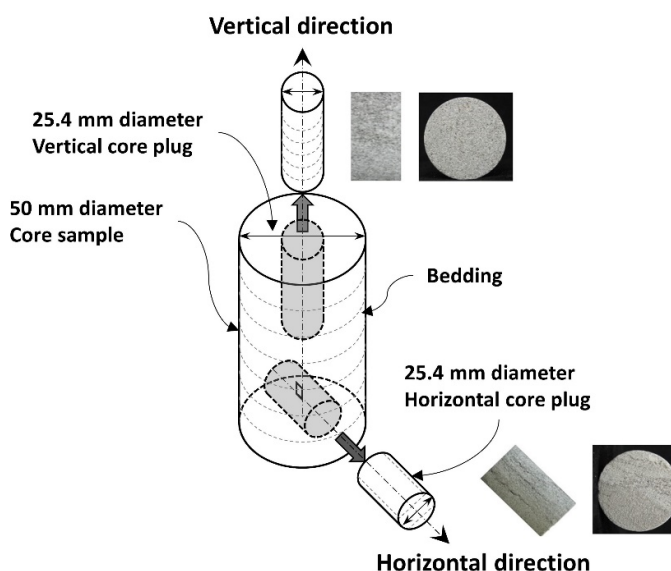


Figure 2. Schematic diagram of directional core preparation.

4. Directional Hydraulic Properties

4.1. Porosity

The theoretical CO₂ storage capacity of a potential reservoir can be estimated as a function of the density of the injected CO₂, pore volume, fluid and skeletal compressibility of the reservoir, reservoir pressure and storage efficiency—although porosity is the principal influencing factor. Thus, accurate porosity measurement was ensured by employing both helium expansion and mercury injection methods, where the pore volume, pore size distribution, and density were each determined. The results obtained using the two methods were compared. However, one must also consider that the theoretical storage capacity can provide an overestimation of the effective storage capacity depending on the geological structure, fluid flow characteristics, injection schemes, and reservoir conditions [19].

4.1.1. Helium Porosimetry

Helium porosity determined using a gas porosimeter is an accurate porosity measurement method. This method is based on isothermal expansion of helium into the sample chamber from the reference chamber, where the bulk volume of the sample and reference chambers are known and the initial helium pressure (~100 psi) is noted. The helium gas was allowed to expand into the sample chamber, and the stabilized pressure recorded. The helium porosity was calculated using Boyle's and Charles' Law. The pore volume was measured directly by re-saturating the sample with helium gas which is both not readily adsorbed onto the mineral surfaces and preferentially enters the micropore structure due to its small molecular size. The sample chamber included two calibration disks with a known volume and fixed temperature, which were used to measure the effective porosity. As a wide range of porosity was expected, helium porosity has been adopted as a conventional technique suitable for samples with porosities ranging from ~1 to ~35%. However, a limitation of the technique is that the bulk volume of relatively small or atypically shaped core samples cannot be measured accurately. In this study, the helium porosity of 25 of the 32 mini core plugs was measured (Table A2), while the remaining 7 core plugs could not be volumetrically measured for bulk volume.

4.1.2. Mercury Porosimetry

As some of the core plugs could not be measured using the helium porosimeter, mercury porosity was determined based on the intrusion of non-wetting mercury at high pressure (~60,000 psi). Mercury porosity measurements can be used to determine various quantifiable rock properties, including porosity, pore volume, pore size distribution, and density [20]. The pore diameter was determined based on the injection pressure, contact angle, and surface tension of mercury. The mercury porosity of one core sample from 739 m (PHOD-1 #9 V-1) and one from 779 m (PHOD-1 #19 H-2) was measured using a mercury porosimeter, where PHOD-1 #9 V-1 had a porosity of 26.05% and bulk density of 1.88 g/cc, and PHOD-1 #19 H-2 had a porosity of 26.98% and bulk density of 1.91 g/cc (Tables A1 and A2). The mercury intruded pores between 0.003 μm and 375 μm , where the peak size was 13.96 μm for PHOD-1 #9 V-1 and 7.25 μm for PHOD-1 #19 H-2 (Figure 3).

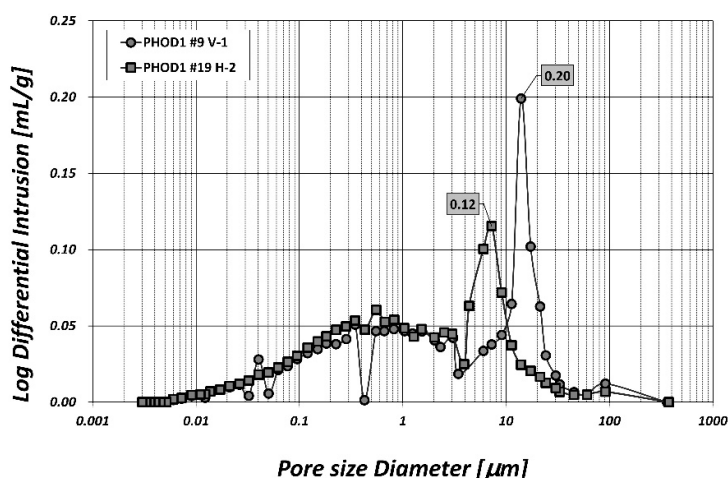


Figure 3. Pore size distribution of samples PHOD-1 #9 V-1 (depth = 739 m) and PHOD-1 #19 H-2 (depth = 779 m).

4.1.3. Comparison of Helium and Mercury Porosities

The porosity profiles determined using the helium and mercury porosimeters ranged between 0.7 and 35.1%. The estimated porosity of the vertical and horizontal core samples based on helium porosity exhibited similar trends (Figure 4). The porosity values of the two core samples measured using the mercury porosimeter were lower than those measured using the helium porosimeter. However, a similar and consistent evaluation of porosity was achieved at depths of 739 m and 779 m using the two techniques. Further, the consistency between the estimated porosity of the vertical and horizontal rock samples demonstrated that these results provided a reasonable prediction of porosity. Thus, the formations around depths of 739 m and 779 m had relatively high porosity and exhibited good potential for CO₂ geological storage.

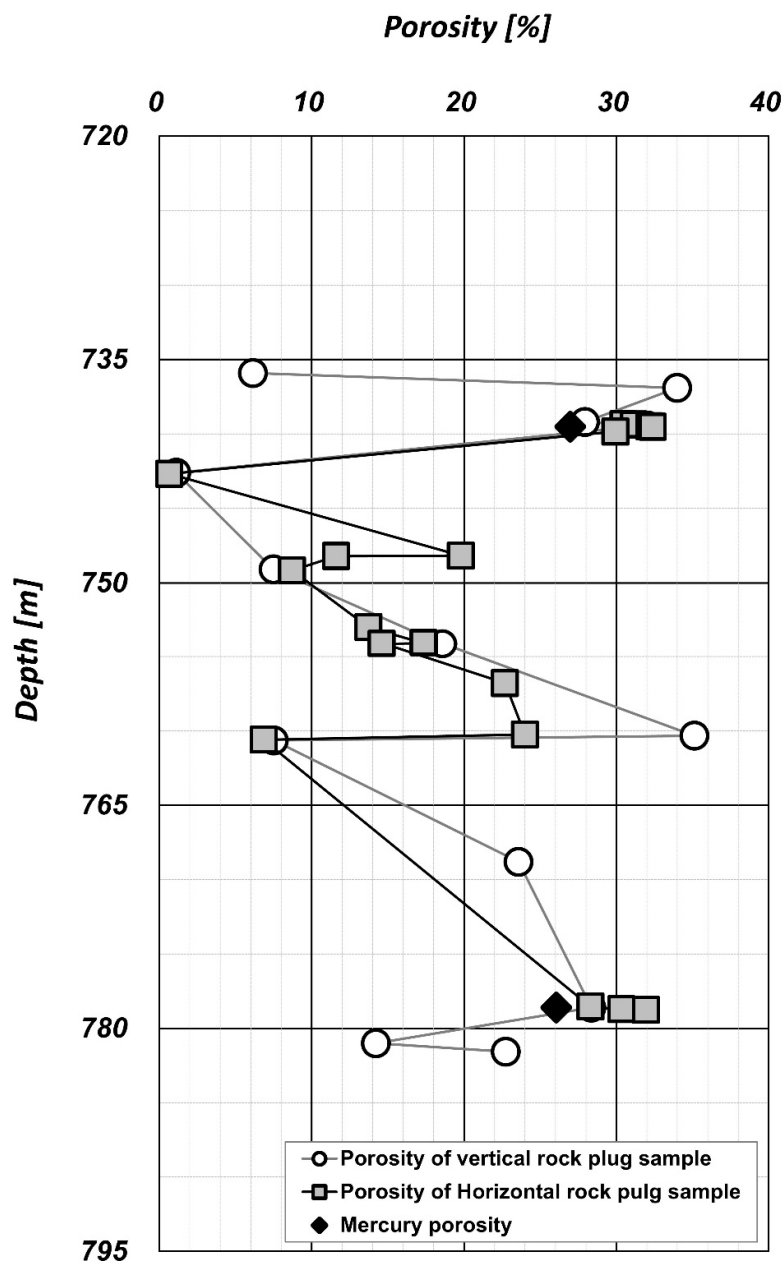


Figure 4. Porosity of plug rock samples determined using helium porosimetry (circles and squares) and mercury porosimetry (diamonds).

4.2. Permeability

The CO₂ injectivity of a potential reservoir is defined as the ability of the geological formation to accept injected CO₂ [21], where permeability represents the capacity of the medium to transmit CO₂. Permeability is a tensor that is generally a function of pressure and related injection rate. In total, two experimental devices were used to evaluate permeability in this study, namely a PPP for rapid gas permeability determination and a broadband rock permeability measurement system for the determination of directional permeability based on the vertically and horizontally cored samples acquired at a similar depth. The PPP offered rapid and easy preliminary measurements, but exhibited poor reliability due to variations in sample surface roughness and human operation. Thus, the unsteady-state method was used in cases where the PPP measurement was less than 1 md, or when the porosity was less than 10% to ensure an accurate estimation of directional permeability.

4.2.1. Portable Probe Permeameter (PPP)

The PPP analyzer (PPP-250, CoreLab, Daejeon, Korea) recorded the rapid gas flow response of the sample [22]. This rapid measurement is used for the rapid determination of gas permeability in outcrops and cores in the laboratory. Specifically, the PPP device measures pressure decay as a function of time under unsteady-state conditions [23] using a system composed of a gas reservoir, probe tip, control panel, and tablet PC. The probe tip was pressed against the rock surface, where the charged pressure did not exceed 50 psi. The pressure of the initial flow decreased as gas flowed into the rock and the pressure-decay versus delay time was recorded to calculate the unsteady-state permeability. In this study, the core samples were fixed using a specialized holder that offered a constant holding pressure (Figure 5).

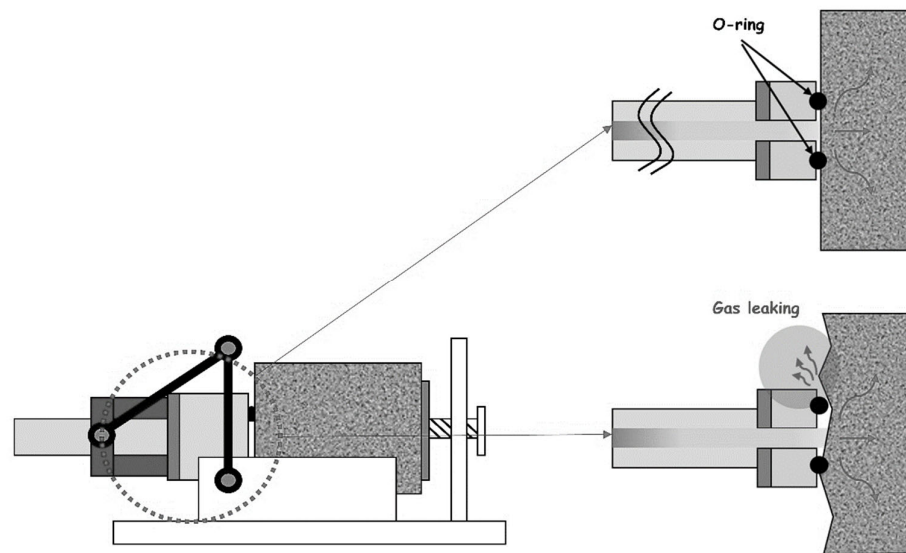


Figure 5. Permeability measurement using the portable probe permeameter.

The samples with a high surface roughness were associated with a high estimated gas permeability due to gas leakage around the probe tip. The permeability values determined using the PPP were used to characterize the permeability variation, and were compared with the directional permeability measured using the broadband rock permeability measurement system.

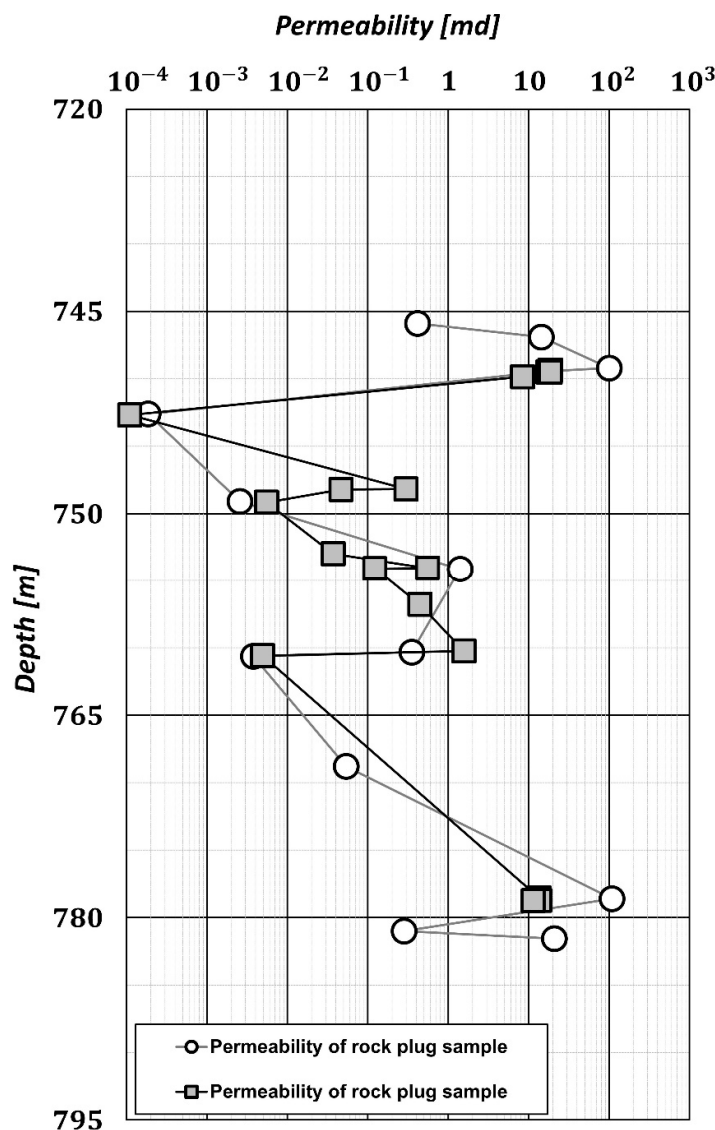


Figure 7. Measured vertical and horizontal permeabilities.

The measurements of porosity and directional permeability define the relationship between the horizontal permeability (k_h) and porosity as $k_h = 0.0004e^{0.4\phi}$ ($R^2 = 0.9668$), and between vertical permeability (k_v) and porosity as $k_v = 0.0011e^{0.3\phi}$ ($R^2 = 0.6333$) (Figure 8). Further, the linear relationship between the vertical and horizontal permeability ratios was $k_v = 1.9 \times k_h^{1.1106}$ (Figure 9). Thus, the vertical permeability is approximately double the horizontal permeability. Overall, these results provide valuable insights into the directional hydraulic properties of the PHOD-1 well, and demonstrate that the two target reservoirs between 730 and 790 m depth have a high potential as CO₂ injection reservoirs. This directional permeability of the prospective CO₂ storage reservoirs is expected to affect their CO₂ injectivity, storage capacity, and migration during CO₂ injection and monitoring.

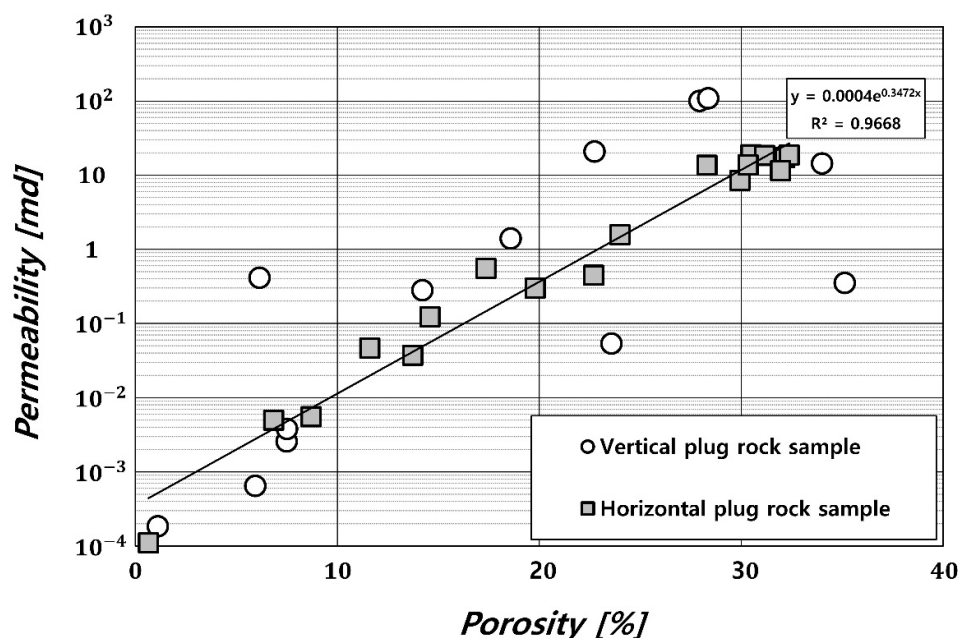


Figure 8. Relationships between porosity and both vertical and horizontal permeabilities.

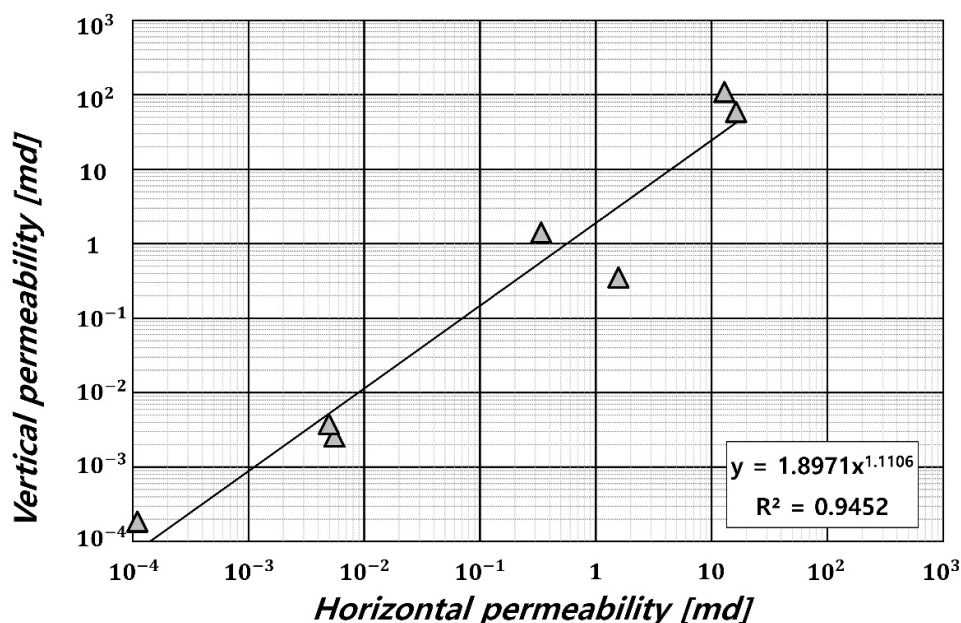


Figure 9. Relationships between vertical and horizontal permeabilities.

6. CO₂ Migration Modeling

Numerical simulations of CO₂ injection and migration were conducted to determine the effects of the injection depth and measured directional permeabilities on the vertical movement of injected CO₂. A dynamic reservoir simulator ECLIPSE 300 (compositional reservoir simulator software from Schlumberger, Version 2016.1) is used to represent a subsurface model based on the measured porosity and horizontal and vertical permeabilities (Figure 10). The model has a simple 1-D grid system with 1566 grids along the z-axis. The dimensions of each grid block are $500 \times 500 \times 0.5 \text{ m}^3$, where the top grid begins from the seafloor. Mud facies were expected from the seafloor to a depth of 735 m, which were represented as low permeability rocks with a mean porosity of 12.58% and

permeability 0.12 md in the upper 1470 grid blocks. These values for mud facies were determined based on laboratory measurements (Table 1). The lower 96 grid blocks represent the potential CO₂ geological storage formation between 735 and 783 m, which are defined based on the series of measured porosity and permeability. CO₂ flow modeling for these grid blocks was conducted as follows:

1. Facies modeling: For each grid, one of the three facies (mud, sand, and conglomerate) is determined by the dominate lithofacies in Figure 1. Facies model is a dominant factor for the following porosity and permeability modeling because statistical parameters in Table 2 and the relation between porosity and permeability are determined by facies.
2. Porosity modeling: The mean and variance of the porosity values were determined for each facies, namely mud, conglomerate, and sand (Table 1). The grids with measured porosity data are assigned to its value, while the grids without porosity data were simulated based on the assumption of Gaussian distribution for sand and mud facies and uniform distribution for conglomerate. Here, statistical information in Table 1 is used to define the distributions.
3. Horizontal permeability modeling: The correlation between measured porosity and horizontal permeability for each facies as below was applied to the previous porosity model. The equations are determined in semi-log coordinate using the experimental result in Table A2.

For mud facies: $k_h = 0.0002 * e^{0.3702 \times \phi}$

For sand and conglomerate facies: $k_h = 0.0019 * e^{0.2884 \times \phi}$

4. Vertical permeability modeling: The correlation between the measured horizontal and vertical permeabilities for each facies as below was applied to the previous vertical permeability model. The equations are determined in log-log coordinate using the experimental result in Table A2.

For mud facies: $k_v = 0.2247 * e^{0.7932 \times k_h}$

For sand and conglomerate facies: $k_v = 6.9965 * e^{0.7508 \times k_h}$

The porosity, vertical permeability, and horizontal permeability models between depths of 735 and 783 m are shown in Figure 10, with the petrophysical parameters for the dynamic simulation listed in Table 3. The CO₂ injection simulation was performed for two different injection depths based on the high injectivity of CO₂ across the thick sand facies zone. Thus, the CO₂ injection well was located in two different target layers, namely at 778 m (Case 1) and 738 m (Case 2). In case of rock compressibility, the single value, $7.25 \times 10^{-5} \text{ bar}^{-1}$ @ 137.2 bar, is assigned regardless of facies. The relative permeability between water and CO₂ used is presented in Table 2.

Table 1. Mean and variance in petrophysical properties for each facies, including porosity, vertical permeability, and horizontal permeability.

Facies	Porosity [%]		Vertical Permeability [md]		Horizontal Permeability [md]	
	Mean	Standard Deviation	Mean	Standard Deviation	Mean	Standard Deviation
Mud	12.58	10.50	0.12	0.18	0.34	0.63
Conglomerate	18.47	6.02	10.58	14.57	21.16	14.57
Sand	26.53	7.12	48.50	51.58	10.11	7.90

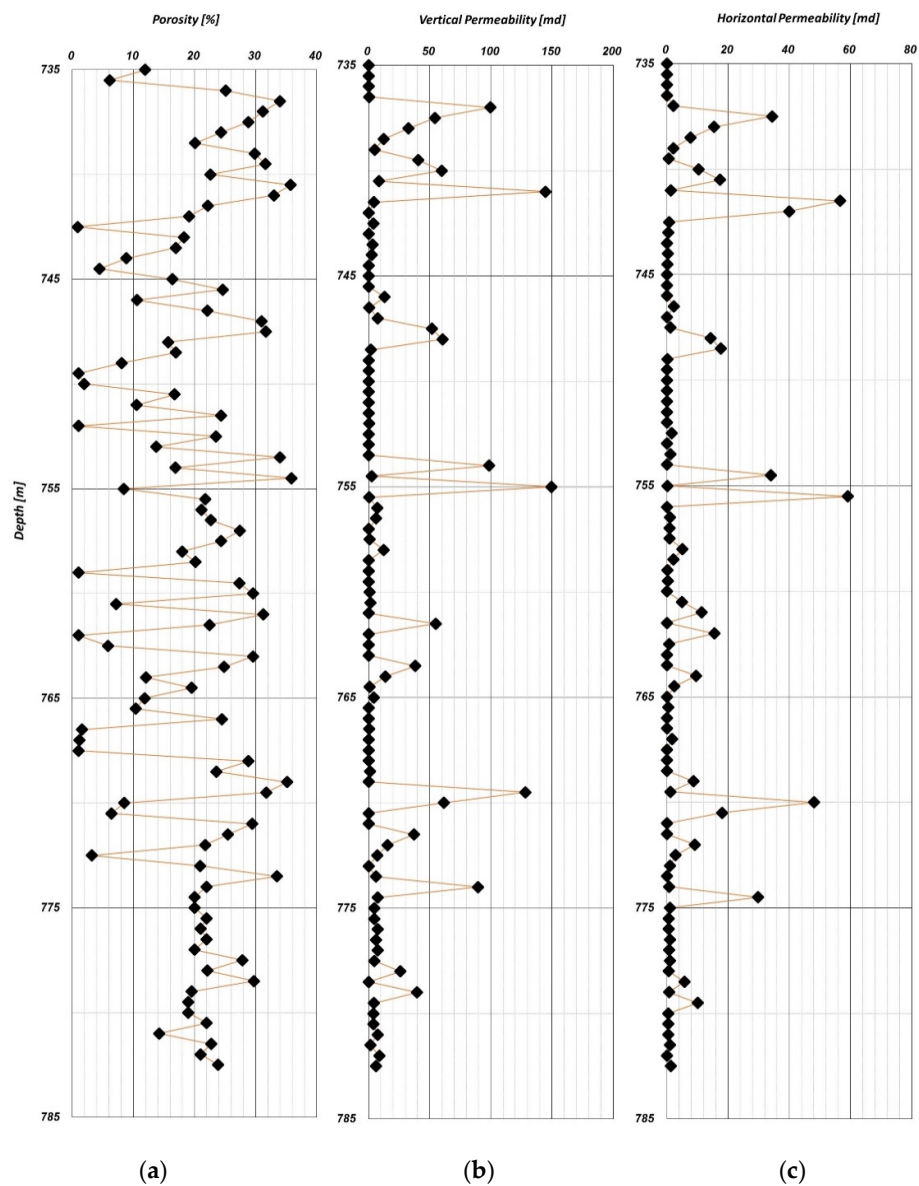


Figure 10. Petrophysical model between 735 and 785 m for (a) porosity, (b) vertical permeability, and (c) horizontal permeability.

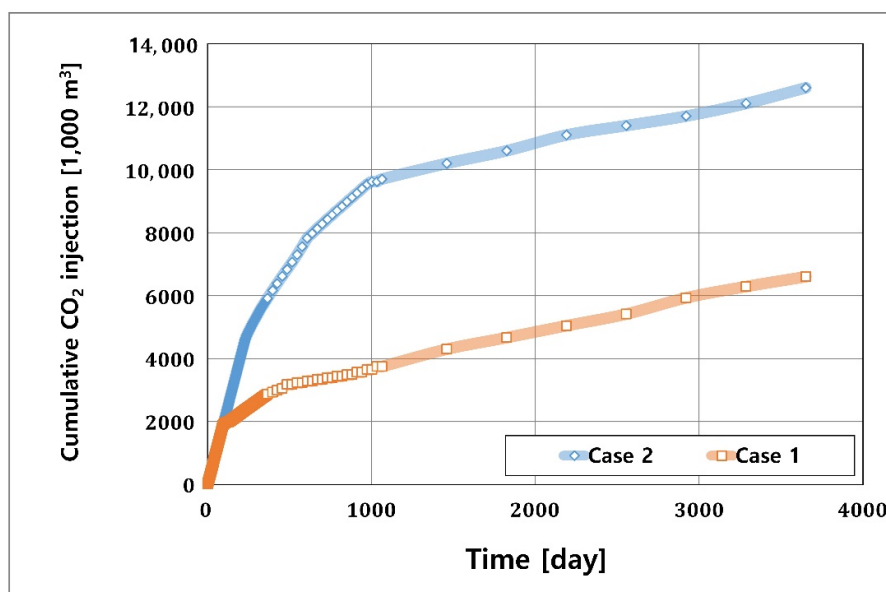
Table 2. Relative permeability for water and CO₂.

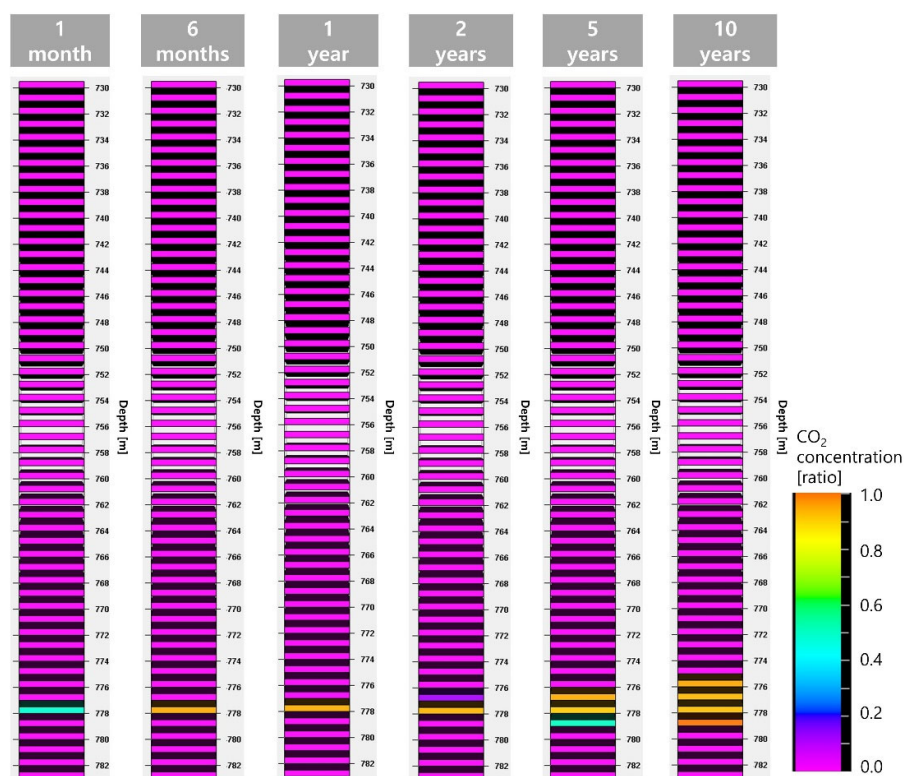
Water Saturation	K _{rw}	K _{rg}
0.3	0	0
0.38	0.000152	0
0.46	0.002439	0.000407
0.53	0.012346	0.005831
0.61	0.039018	0.024131
0.69	0.09526	0.064892
0.77	0.197531	0.140566
0.84	0.36595	0.269314
0.92	0.624295	0.484797
1.0	1	1

Table 3. Input parameters for numerical modelling of CO₂ flow.

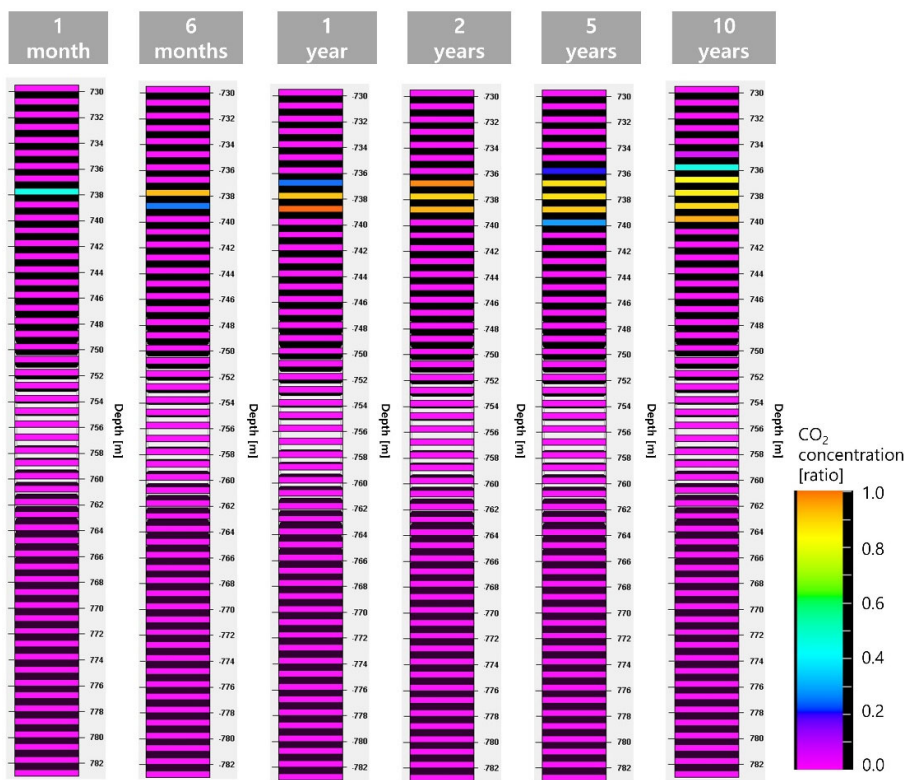
Parameter	Value
Initial conditions	Pressure [bar]
	80 at 730 m
	Temperature [°C]
	60 at 730 m
	Oil-water contact depth [m]
	0 (seafloor)
Injection well	Injection rate [m ³ /day]
	20,202
	Max. bottom-hole pressure [bar]
	120
	Perforation [m]
	777.5~778.5 (Case 1)
	737.5~738.5 (Case 2)
Simulation time [years]	10

The cumulative CO₂ injection volumes at the end of CO₂ injection over periods of 10 years were 6601 Mm³ for Case 1, and 12,600 Mm³ for Case 2 (Figure 11). Case 2 exhibited an injection efficiency double that of Case 1 because the petrophysical models (Figure 10) exhibited much higher values close to 738 m compared to 778 m. The distribution of CO₂ concentration at 1 month, 6 months, 1 year, 2 years, 5 years, and 10 years demonstrated high security of storage for CO₂ against leakage to the seafloor (Figure 12), where the injected CO₂ remained confined between 774.25 and 779.25 m in Case 1 (Figure 12a) and between 732.75 and 740.25 m in Case 2 (Figure 12b). Thus, the injected CO₂ was contained in the sand, mud, and conglomerate formations, which served as barriers for CO₂ storage.

**Figure 11.** Cumulative CO₂ injection volume at depths of 778 m (Case 1) and 738 m (Case 2).



(a) Case 1



(b) Case 2

Figure 12. CO₂ concentration over the interval 730 m to 783 m at 1 month, 6 months, 1 year, 2 years, 5 years, 10 years for (a) Case 1 and (b) Case 2.

7. Conclusions

This study characterized the directional hydraulic properties of a potential CO₂ geological storage site in the Pohang Basin, southeast Korea. The porosity and directional permeability of directionally plugged rock core samples were determined. The permeability measurement method was chosen based on a threshold screened permeability of 1 md, which was rapidly determined using a portable probe permeameter (PPP). Subsequently, the vertical and horizontal permeabilities were measured using a more accurate a newly development system. The two promising geological formations, at depths of ~739 and ~779 m, were investigated as prospective CO₂ storage reservoirs with high porosities (32 and 28%, respectively) and permeabilities (over hundreds of millidarcy for both). Both geological formations consisted of a series of thick layers of porous sandstone, and were found to be suitable for geological storage and injection of CO₂.

Numerical modeling of injected CO₂ plume migration was conducted to analyze the subsequent flow of CO₂ into the reservoir and through the overlying formations, where the measured directional hydraulic properties were used. The injection efficiency for the formation at 738 m was double that at 778 m. The leakage model demonstrated that CO₂ was largely contained within the sand, mud, and conglomerate facies, which served as barriers to facilitate CO₂ storage for at least 10 years. The determined directional hydraulic properties and experimental techniques used to identify the potential CO₂ geological storage sites in this study can be used for further CO₂ storage capacity, injectivity, and leakage risk assessment.

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Conflicts of Interest: The authors declare no conflicts of interest.

Appendix A

Table A1. Properties of recovered core plugs from well PHOD-1 and densities of directionally prepared core plugs.

No.	Core Plug ID	Top Depth [m]	Diameter [mm]	Length [mm]	Bulk Density [g/cm ³]	Saturated Density [g/cm ³]	Direction
1	PHOD-1 #41 V-1	705.7	25.8	50.1	-	-	Vertical
2	PHOD-1 #39 V-1	735.9	25.7	17.0	-	-	Vertical
3	PHOD-1 #18 V-1	736.9	25.9	25.1	1.7	1.9	Vertical
4	PHOD-1 #5 V-1	739.2	38.0	70.3	-	2.1	Vertical
5	PHOD-1 #11 H-1	739.4	25.8	31.7	1.8	2.0	Horizontal
6	PHOD-1-#11 H-2	739.4	26.0	28.3	1.8	2.0	Horizontal
7	PHOD-1-#19 V-1	739.4	25.8	31.7	1.8	2.0	Vertical
8	PHOD-1-#19 H-1	739.5	26.0	28.0	1.8	2.0	Horizontal
9	PHOD-1-#19 H-2	739.5	26.0	31.1	1.9	-	Horizontal
10	PHOD-1-#20 H-1	739.8	25.6	25.9	1.8	2.0	Horizontal
11	PHOD-1 #12 V-1	742.6	26.1	51.6	2.5	2.6	Vertical
12	PHOD-1 #21 H-1	742.7	26.1	35.6	2.5	2.6	Horizontal

13	PHOD-1 #26 H-1	748.2	26.1	35.9	2.1	-	Horizontal
14	PHOD-1 #26 H-2	748.2	26.0	34.1	2.3	2.4	Horizontal
15	PHOD-1 #27 V-1	749.1	26.1	64.7	2.3	2.4	Vertical
16	PHOD-1 #27 H-2	749.2	26.1	34.0	1.6	-	Horizontal
17	PHOD-1 #28 H-3	753.0	26.1	34.6	2.3	2.4	Horizontal
18	PHOD-1 #29 H-1	754.1	26.0	35.1	2.2	2.3	Horizontal
19	PHOD-1 #29 H-2	754.1	26.0	35.5	2.2	2.4	Horizontal
20	PHOD-1 #29 V-1	754.1	26.1	60.9	-	2.3	Vertical
21	PHOD-1 #31 H-2	756.8	26.0	33.5	2.0	2.3	Horizontal
22	PHOD-1 #32 H-1	760.3	26.0	34.8	2.0	2.2	Horizontal
23	PHOD-1 #32 V-1	760.3	26.0	26.0	1.8	2.0	Vertical
24	PHOD-1 #33 H-1	760.6	26.0	32.6	2.5	2.6	Horizontal
25	PHOD-1 #33 V-1	760.6	26.1	55.5	-	2.0	Vertical
26	PHOD-1 #4 V-1	768.8	38.3	73.1	-	-	Vertical
27	PHOD-1 #14 H-2	778.6	26.0	34.8	1.9	2.1	Horizontal
28	PHOD-1 #9 V-1	778.6	38.1	69.8	1.9	-	Vertical
29	PHOD-1 #9 H-1	778.7	25.9	33.9	1.8	2.0	Horizontal
30	PHOD-1 #9 H-2	778.8	26.0	34.0	1.8	2.0	Horizontal
31	PHOD-1 #2 V-1	781.0	38.3	54.8	-	-	Vertical
32	PHOD-1 #10 V-1	781.6	36.7	60.1	2.0	2.3	Vertical

Table A2. Porosity measurements from helium porosimetry and mercury porosimetry and permeability measurements from Pressure Pulse Decay (PPD) and Steady State Methods (SSM).

No.	Core Plug ID	Top Depth	Porosity	Permeability	Measurement Method
		[m]	[%]	[md]	[-]
1	PHOD-1 #41 V-1	705.7	5.9	<0.1	² PPD
2	PHOD-1 #39 V-1	735.9	6.1	<0.1	PPD
3	PHOD-1 #18 V-1	736.9	34.0	>1000	³ SSM
4	PHOD-1 #11 H-1	739.4	30.5	51.5	SSM
5	PHOD-1 #11 H-2	739.4	31.2	141.5	SSM
6	PHOD-1 #19 V-1	739.4	26.9, 32.0 ⁽¹ MP)	>1000	SSM
7	PHOD-1 #19 H-1	739.5	32.2	81.1	SSM
8	PHOD-1 #20 H-1	739.8	29.9	68.1	SSM
9	PHOD-1 #12 H-1	742.6	-	10.2	SSM
10	PHOD-1 #12 V-1	742.6	1.1	1.6	SSM
11	PHOD-1 #21 H-1	742.7	0.7	-	None
12	PHOD-1 #24 H-1	744.2	-	1.3	SSM
13	PHOD-1 #25 H-1	746.2	-	2.2	SSM
14	PHOD-1 #26 H-1	748.2	19.8	5.9	SSM
15	PHOD-1 #27 H-1	749.1	8.7	0.4	PPD
16	PHOD-1 #27 V-1	749.1	7.5	0.7	PPD
17	PHOD-1 #27 V-2	749.2	-	5.4	SSM
18	PHOD-1 #28 V-2	752.9	-	3.8	SSM
19	PHOD-1 #28 H-3	753.0	13.7	0.2	PPD
20	PHOD-1 #29 H-1	754.1	17.4	9.5	SSM
21	PHOD-1 #29 H-2	754.1	14.6	18.6	SSM
22	PHOD-1 #29 V-1	754.1	18.6	45.7	SSM
23	PHOD-1 #30 H-1	755.7	-	11.0	SSM
24	PHOD-1 #30 H-2	755.9	-	7.7	SSM
25	PHOD-1 #31 H-1	756.7	22.7	0.7	PPD
26	PHOD-1 #31 V-1	756.8	-	3.9	SSM
27	PHOD-1 #31 H-2	756.8	-	10.3	SSM
28	PHOD-1 #32 H-1	760.3	24.0	38.3	SSM

29	PHOD-1 #32 H-2	760.3	-	8.4	SSM
30	PHOD-1 #32 V-1	760.3	35.1	26.8	SSM
31	PHOD-1 #33 V-1	760.6	7.5	13.7	SSM
32	PHOD-1 #33 H-3	760.7	-	1.4	SSM
33	PHOD-1 #4 V-1	768.8	23.6	>1000	SSM
34	PHOD-1 #13 H-2	778.4	-	17.0	SSM
35	PHOD-1 #14 H-1	778.5	-	15.7	SSM
36	PHOD-1 #14 H-2	778.6	28.3	144.0	SSM
37	PHOD-1 #9 V-1	778.6	26.1, 28.4 (MP)	>1000	SSM
38	PHOD-1 #10 V-1	781.6	22.7	90.3	SSM

¹ MP: Mercury Porosity. ² PPD: Pressure pulse decay (unsteady state method). ³ SSM: Steady State Method.

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